SOUTHERN CALIFORNIA EDISON®

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# SOUTHERN CALIFORNIA EDISON

## Smart Grid Annual Deployment Plan Update

October 1, 2016

# Smart Grid Deployment Plan Annual Report

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## I. Executive Summary

California's landmark Smart Grid legislation, Senate Bill (SB) 17, established that "[i]t is the policy of the state to modernize the state's electrical transmission and distribution system to maintain safe, reliable, efficient, and secure electrical service, with infrastructure that can meet future growth in demand and achieve" various goals aimed at a cleaner energy future, energy efficiency, and more engaged customers.[1] SB 17 mandated that electric utilities submit smart grid deployment plans to the California Public Utilities Commission (CPUC or Commission) for approval. Southern California Edison Company (SCE) submitted its Smart Grid Deployment Plan on July 1, 2011.[2] The Commission ruled on these plans during their July 25, 2013 business meeting, voting unanimously to approve the plans submitted by the electric utilities.[3]

Also, SB 17 required the Commission provide an annual report to the Governor and the Legislature "on the commission's recommendations for a smart grid, the plans and deployment of smart grid technologies by the state's electrical corporations, and the costs and benefits to ratepayers."[4] In turn, the Commission ordered the California investor-owned electric utilities (IOUs) to provide an annual update on the status of their Smart Grid investments.[5] In the annual update reports, SCE (in compliance with D. 10-06-047) explains the following: (1) deployment of Smart Grid technologies; (2) progress toward meeting the utility's Smart Grid Deployment Plan; (3) the costs and benefits to ratepayers, where such assessments were feasible; (4) current deployment and investment initiatives; (5) updates to security risk and privacy threat assessments; and (6) compliance with security rules, guidelines, and standards.[6] On August 2, 2013, the Commission issued D. 13-07-024 adopting the report template and format used by the IOUs for their annual updates reporting on the progress of its smart grid projects and initiatives.

On December 4, 2014, the Commission issued Decision (D.)14-12-004 closing the Smart Grid proceeding, formally known as the *Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System.* [7]

In this latest annual report, the 5th update to the Smart Grid Deployment Plan, SCE provides an update to cover the most recent reporting period of July 1, 2015 through June 30, 2016 (Reporting Period). Through this Smart Grid Deployment Plan Update, SCE complies with its reporting obligation and assists the Commission in developing the Commission's own annual report to the Governor and the Legislature.

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1 Pub. Util. Code § 8360.
2 *See* Application (A.) 11-07-001.
3 Decision (D.) 13-07-024.
4 PUB. UTIL. CODE § 8367.
5 Decision (D.) 10-06-047, Ordering Paragraph 15.
6 *Id.*
7 R.08-12-009.

In the Smart Grid Deployment Plan, SCE described its deployment baseline and its vision for the Smart Grid. This Update details SCE's progress on specific projects. There are six types of projects:

1. Customer Empowerment;
2. Distribution Automation/Reliability;
3. Transmission Automation/Reliability;
4. Asset Management & Operation Efficiency;
5. Security; and
6. Integrated & Cross-Cutting Systems.

SCE's **Customer Empowerment** efforts provide customers with information regarding their energy usage, as well as programs, rates, and technologies to enable energy conservation and peak load reductions. This energy information (e.g., interval usage data, near real-time usage and cost information, event notifications) will better facilitate customers' ability to participate in time-variant rates. These customer-oriented efforts will also provide information accessible in a variety of ways (e.g., web and mobile devices) to customers and authorized third-party service providers. During the Reporting Period, SCE conducted various customer empowerment initiatives, including:

- Continuing to implement the Energy Service Provider Interface (ESPI), a technology platform and infrastructure to enable third parties, when authorized by a customer, to receive that customer's usage data in a secure and automated manner;
- Completing the Plug-In Electric Vehicle (PEV) Workplace Charging Pilot to gain a better understanding of consumer behavior related to fee-based charging and DR events in order to advise business customers regarding the costs, benefits, and impacts of workplace charging to provide information for future installation plans at customer properties; and
- Successfully implementing the improvement program that used a multi-phased approach to enable a scalable platform for SCE customers to enroll and receive proactive digital maintenance and repair outage notifications.

**Distribution Automation/Reliability** (DAR) projects improve information and control capabilities for distribution systems. These projects focus on distribution challenges posed by distributed energy resources, clustered electric vehicle charging, and also mitigate outages by developing self-healing circuit technology. As part of DAR, SCE continued to improve on its distribution information systems such as the Geographical Information System, Consolidated Mobile Solutions and Distribution Management System. These projects will provide a consolidated solution to manage safety, reliability, and compliance obligations. Additionally, SCE is in the process of developing and constructing an SCE owned energized Equipment Demonstration and Evaluation Facility to house a new 12 kV test circuit which will allow engineers to perform evaluations of emerging technologies on energized, high-voltage equipment and distribution circuits in real world conditions.

**Transmission Automation/Reliability** (TAR) projects address similar issues on the transmission system. These projects allow us to incorporate utility-sized intermittent power generation such as solar and wind energy in a safe and reliable manner. TAR projects also enhance data collection and automation to prevent wide-scale blackouts. For example, SCE completed a Centralized Remedial Action Scheme (CRAS) to address increased interconnection complexities. CRAS improves architecture, management, oversight, and effectiveness of remedial action, and also reduces tripping of generation and/or shedding of load as needed. During this Reporting Period, CRAS is nearly complete and in the stabilization phase.

**Asset Management & Operation Efficiency** projects improve the efficiency of grid operations. These projects identify infrastructure replacements based on asset health rather than time in service; the projects help prevent critical equipment failure. As an example, a pilot was initiated to resolve server issues with transformer data being transmitted from a Remote Terminal Unit (RTU) to the Grid Control Center (GCC) and is currently being conducted in the Online Transformer Monitoring Project. Active dissolved gas analysis (DGA) projects are continuing to be engineered and constructed up to the RTU until resolution of the pilot to determine the required steps to complete all phases of a DGA process.

**Security** projects address both cyber and physical security. These projects address the increased security requirements associated with developing, implementing, operating, and managing Smart Grid systems and assets. As part of its efforts related to security, SCE has developed a Common Cybersecurity Services (CCS) platform to protect its grid infrastructure. During the Reporting Period, CCS completed system acceptance testing and the installation and operation of CCS in 27 bulk electric substations.

Finally, **Integrated & Cross-Cutting Systems** refer to projects that support multiple Smart Grid domains (e.g., communications, data management and testing). An integrated approach creates a platform to deliver benefits across utility operations and share those benefits with customers. Integrated systems also enable information sharing between the utility, service partners, and customers. SCE's Advanced Technology Labs are part of this category and provide SCE engineers with an integrated environment to test the spectrum of Smart Grid projects, from renewable generation to substation automation to plug-in electric vehicles (PEVs).

With respect to benefits, these projects are intended to provide benefits to customers in the form of better system reliability, improved safety and security, increased customer choice and reduced costs. The Department of Energy's Office of Electricity Delivery and Energy Reliability (DOE) developed a methodology to quantify Smart Grid benefits as part of the American Recovery and Reinvestment Act effort. For purposes of this report, SCE's benefits calculation is based on DOE's methodology, which has been tailored to SCE's operating environment.

It is worth noting that SCE's Smart Grid vision also carries with it risks and challenges. As noted in previous updates, the grid was initially designed to carry power in one direction from the generator to the end use consumer. Changes in state and federal energy policy (e.g., distributed generation and energy storage) are causing utilities to rethink the initial design and develop a means to create a more flexible delivery system that remains safe, affordable and reliable. This will likely include a transition

from more conventional technologies to smarter, computer-based assets, capable of communicating and optimizing. This update details SCE's continued activities toward these goals. Importantly, this transition will be more cost-effective if the technologies are based on common standards. As SCE has maintained since Phase 1 of the Smart Grid OIR (R.08-12-009), standards are necessary to help ensure interoperability and maximize market participation.

The importance of cybersecurity to the utility industry and to SCE has increased as systems and data have become more integral to business operations, and as cyber threats continue to grow in number and sophistication. SCE continues to work with the government and private industry to develop and deploy critical infrastructure protection as evidenced by our implementation of a Common Cybersecurity Services (CCS) platform currently deployed on our bulk electric system. SCE continues to work with the vendor community to satisfy various cybersecurity protocols, including the National American Electric Reliability Corporation (NERC) CIP standards and the National Institute of Standards and Technology's (NIST) requirements. The industry anticipates that Federal Energy Regulatory Commission (FERC) and NERC will continue to require improved CIP reliability standards over the next several years, but is prepared to meet them, as cybersecurity is critical for Smart Grid development.

As part of its smart grid efforts, SCE proactively engages with and educates residential customers, business customers, governmental entities, and other stakeholders. During the Reporting Period, SCE continued to inform customers about online energy management tools and services, develop an outage application for smart phones, and enroll customers in the Save Power Day program. SCE also provided marketing, education and outreach to its customers regarding to its web presentment tools, time-of-use (TOU) rates (including rates for plug-in electric vehicles), Budget Assistant, and Save Power Day programs.

In sum, SCE continued to advance its Smart Grid initiatives, consistent with the requirements of SB 17 and D. 13-07-024. SCE will continue to work with the Commission, fellow utilities, and stakeholders to modernize the grid in support of state and federal energy policy objectives.

## II. Plan Update

In this section, SCE provides an update on proceedings and benefits associated to the Smart Grid Deployment Plan.

### 2.1 Proceedings

SCE's decision to invest in Smart Grid technologies and fund their deployment is significantly affected by the policy environment in which it operates. This section provides a summary of key state and federal regulatory proceedings and legislative activities impacting or with the potential to impact SCE operations.

The most significant proceeding affecting Smart Grid efforts is the General Rate Case (GRC), because the GRC provides SCE with the base funding and authorization to perform Smart Grid-related work. During the Reporting Period, SCE received a Final Decision on its GRC Proceeding for a 2015 test year, and prepared and submitted an Application on its GRC Proceeding for a 2018 test year. On November 5,

2015, the Commission issued a Final Decision (D.)15-11-021 closing the 2015 GRC proceeding. The majority of SCE's GRC related Smart Grid projects were approved. For example, through the GRC, SCE requested 2015 test-year funding of approximately $9 million[8] for Circuit and Capacitor Automation projects. The Decision approved and authorized both projects that are included in the Distribution Automation/Reliability project space. SCE submitted its most recent GRC Application for a 2018 test year on September 1, 2016.[9] As of the end of the Reporting Period, this proceeding is still open.

On December 4, 2014, the Commission issued Decision (D.)14-12-004 closing the Smart Grid Rulemaking proceeding. Per the Decision, SCE will now submit the mandated Smart Grid Deployment Plan Updates and the quarterly American Recovery and Reinvestment Act (ARRA) project reports to the director of the Energy Division and the Executive Director. [10,11]

Within the Energy Storage rulemaking[12], the Commission issued D.13-10-040, *Decision Adopting Energy Storage Procurement Framework and Design Program* (Program). The decision established the policies and mechanisms for procurement of electric energy storage pursuant to AB 2514, setting an energy storage procurement target for SCE, Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (collectively, the IOUs) of 1,325 MW by 2020. Furthermore, the decision directs the IOUs to file separate biennial applications containing a proposal for their energy storage procurement period starting in 2014. SCE submitted its "Application of its 2014 Energy Storage Procurement Plan" and associated testimony on February 28, 2014.[13] The Commission approved SCE's 2014 Energy Storage Procurement Application in October 2014.[14] The Commission approved SCE's existing storage as eligible towards the targets, authorized SCE's plan for its December 1, 2014 Storage Request for Offers, and accepted SCE's storage cost recovery proposal with one exception related to the Power Charge Indifference Adjustment. SCE submitted its Application for Approval of its 2016 Energy Storage Procurement Plan and associated testimony on March 1, 2016.[15] SCE met its 2016 target and does not need to procure additional storage at this time, but still plans to conduct a 2016 Energy Storage solicitation to maintain momentum in transforming the energy storage market.

In December 2014, the California Independent System Operator (CAISO), the Commission and the California Energy Commission (CEC), in cooperation with interested parties, published "Advancing and Maximizing the Value of Energy Storage Technology: A California Roadmap" (Storage Roadmap) to address ongoing challenges associated with continued expansion of energy storage in California. The Storage Roadmap identified needed actions, set priorities and defined the responsibilities of each organization to address the challenges. On March 26, 2015, the Commission filed an Order Instituting

8 In 2012 dollars
9 Application (A.)16-09-001.
10 D.14-12-004.
11 ARRA Projects: Tehachapi Wind Energy Storage Project (TSP) and the Irvine Smart Grid Demonstration (ISGD) per Rulemaking R.08-12-009.
12 R.10-12-007.
13 A.14-02-009.
14 D.14.10-045.
15 A.16-03-002.

Rulemaking (OIR) to address the enactment and ongoing implementation of California Assembly Bill 2514 and to continue to refine policies and program details as required or recommended by Decisions (D.) 13-10-040 and D.14-10-045, which established the Energy Storage Procurement Framework Program and approved the utilities' applications in implementing the Program.[16] On January 28, 2016, the Commission issued the Track 1 Decision 16-01-032 which, among other things, maintained the investor-owned utilities' flexibility to design their request for offer ("RFO") processes, allowed greater flexibility of energy storage targets among grid domains, and extended the authorization of the Power Charge Indifference Adjustment mechanism for "bundled" energy storage services procured via the 2016 solicitation.[17]

The Electric Program Investment Charge (EPIC) is administrated by the Utilities (PG&E, SCE and SDG&E) and the CEC. The EPIC Program provides funding for applied research and development, technology demonstration and deployment and market facilitation of clean energy technology. EPIC's budget is annually $162 million and is collected from customers using the following allocation: PG&E (50.1%), SCE (41.1%) and SDG&E (8.8%), resulting in SCE's triennial budget of $40 million. The Utilities are limited to technology demonstrations and deployments. SCE has submitted and received Commission approval for two triennial investment plan applications addressing investments in years 2012-2014[18] and investments in years 2015-2017[19]. On September 18, 2015, the Commission approved a regulatory mechanism for new EPIC projects and materially re-scoped EPIC projects via a Tier 3 advice letter filing.

The 21st Century Energy Systems Project (CES-21) is a $35 million, five-year cooperative research and development agreement between SCE, PG&E, SDG&E and Lawrence Livermore National Laboratory (LLNL), which addresses cybersecurity and grid integration issues. On March 27, 2014, the Commission issued D.14-03-029, approving the CES-21 Program. Importantly, the Decision modifies D.12-12-031 to conform to recent California Legislation, SB 96. On October 2, 2014, the Commission issued final approval of the CES-21 Program which authorized the joint IOU's, in a cooperative relationship with LLNL and other national labs, to spend $33 million over five years on a cyber-security project that addresses machine-to-machine automated threat response. The Joint-IOUs received approval of the Cooperative Research and Development Agreement (CRADA). The Joint-IOUs received approval of this in December 2014. The cybersecurity project is in progress and the joint IOUs, along with LLNL provide periodic briefings to Commission staff on a biannual basis.

On September 25, 2013, the Commission issued R.13-09-011 to enhance the role of Demand Response (DR) in meeting California's resource planning needs and operational requirements. The Rulemaking will establish policies to inform future DR program design. SCE was party to a proposed settlement filed on August 4, 2014 that would resolve the majority of the policy issues in the proceeding.[20] SCE filed its

16 R. 15-03-011.
17 A.16-03-002.
18 A.12-11-004, approved in Commission Decision (D.)13-11-025.
19 A.14-05-005, approved in Commission D.15-04-020.
20 D.14-12-024.

Bridge Funding Proposal for 2017 DR Programs on February 1, 2016. On June 16, 2016, the Commission issued a final Decision 16-06-029 adopting bridge funding for 2017 DR programs and activities.

SCE continues to participate in the Commission's Alternative-Fueled Vehicle (AFV) Order Instituting Rulemaking (OIR).[21] SCE and other stakeholders have continually collaborated to develop a sub-metering protocol during Phase 4. On November 14, 2013, the Commission issued D.13-11-007, modifying the requirements for the development of plug-in electric vehicle sub-metering protocol, adopting and Energy Division Staff Roadmap for a two-phased pilot project and extending until September 30, 2015, the deadline for the IOUs to submit a final proposal for the sub-metering protocol. Subsequent to the aforementioned decision, the Commission issued an Order Instituting Rulemaking to consider alternative-fueled vehicle programs, tariffs, and policies.[22] This rulemaking will continue the work started in R.09-08-009, to support California Executive Order B-16-2012, which sets a target of 1.5 million zero-emission vehicles on the roads in California by 2025.[23] The rulemaking has three phases: Phase 1 is focused on policy issues like utility ownership of PEV infrastructure, Phase 2 discusses bidirectional flow for vehicle-grid integration, and Phase 3 addresses rate and financing issues.

On December 18, 2014, the Commission approved a Decision on Phase 1 of the AFV Order Instituting Rulemaking (OIR). [24] The Decision lifted a blanket prohibition against utilities owning EV charging infrastructure, letting them own charging ports and stations on a case-by-case basis. Under the Commission's previous rules, utilities had to show a market failure or an under-served market when filing a request to own EV charging infrastructure. [25] Per D.14-12-079, the Commission will evaluate utility PEV infrastructure ownership proposals on a case-specific basis instead of establishing an upfront acceptable level of utility activity. On March 30, 2016, the Commission issued an Amended Scoping Memo and Ruling for the AFV OIR, to include within the scope of the proceeding the transportation electrification (TE) issues contained in SB 350, and reprioritize the broad policy activities in the AFV OIR. TE applications will be submitted in Q3 of 2016.

In addition to Commission proceedings and filings, smart grid deployment is also affected by federal regulatory decisions, such as the CIP standards developed by the NERC and adopted by the FERC. CIP standards set a regulatory cybersecurity framework for protecting SCE's critical assets. On November 21, 2013, FERC approved NERC CIP Version 5. Industry members worked with NERC staff to develop Revised CIP V5 Reliability Standards that addressed the several directives that FERC issued in Order 791. The revised standards were submitted to FERC on February 13, 2015 and FERC issued a Notice of Proposed Rulemaking proposing to accept the revised standards on July 16, 2015. The CIP V5 compliance deadline was April 1 2016. On January 21, 2016 FERC issued Order 822 approving NERC CIP Version 6 with a compliance date of July 1, 2016. The proposed standards are designed to mitigate the cybersecurity risks to bulk electric system facilities, systems, and equipment, which, if destroyed,

[21] R.09-08-009.
[22] R.13-11-007.
[23] California Executive Order B-16-2012 was issued on March 23, 2012.
[24] D.14-12-079.
[25] D.11-07-029.

degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the Bulk-Power System.

Additionally, SCE is actively evaluating the impact of complying with NERC Reliability Standard CIP-014-1 (Physical Security) requirements for its bulk electric system to comport with pending legislation SB 699. Reliability Standard CIP-014-1 was submitted by NERC to FERC for approval on March 7, 2014. The purpose of CIP-014-1 is to enhance physical security measures for the most critical Bulk-Power System against physical attacks.[26] On June 11, 2015, the CPUC voted to approve a new OIR to address physical security and emergency preparedness. [27] The purpose of the OIR is to consider the establishment of new rules and standards and/or update existing requirements regarding the physical security of electric supply facilities (SB 699 / PU Code 364), and disaster and emergency preparedness plans for electric and water utilities (AB 1650 / PU Code 768.6). This rulemaking will be conducted in phases. The first phase will address physical security and additional phases will address emergency and disaster preparedness plans. SCE filed comments in Physical Security & Emergency Preparedness OIR on July 22, 2015 that addressed: 1) whether the preliminary scope of the proceeding is appropriate; and 2) the schedule, categorization, and need for hearings. In a later phase, the Commission intends to establish standards for disaster and emergency preparedness planning consistent with PU Code Section 768.6. In late November 2015, as a result of $5 million reduction in Public Utilities Commission Utilities Reimbursement Account funding (Fund 0462) by the Legislature, the Commission declared it would delay the Electric Grid Security proceeding (R.15-06-009) until FY 2016/17. The Commission stated that physical security for critical facilities is already being addressed by FERC and NERC.

On August 14, 2014, the Commission issued Rulemaking (R.) 14-08-013 to establish policies, procedures, and rules to guide California IOUs in developing their Distribution Resources Plan (DRP) Proposals, which were due July 1, 2015 pursuant to AB 327. The Rulemaking also intends to evaluate the IOUs existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources (DERs) into the planning and operations of their electric distribution systems. On February 6, 2015, Commissioner Picker issued a ruling to provide final guidance for the content and structure for the DRP proposals. On July 1, 2015, SCE filed the DRP[28] that is intended to serve as a foundation for the evolution of the grid that will support state goals such as reducing GHG emissions, accommodating two-way energy flows, enabling greater customer choice, and creating new opportunities for DERs to provide benefits to the grid.

SCE's DRP identified grid modernization investments to build a 21st century power system capable of supporting a future with greater system reliability and high penetration of DERs. These investments are intended to facilitate DERs by: (1) expediting interconnection processing, (2) creating increased operator situational awareness, (3) enabling more accurate forecasting and planning, and (4) creating greater interaction between the grid and DER operations. In addition to modernization, a complementary set of investments will be needed to increase grid capacity. These "grid reinforcement" investments include:

[26] On July 17, 2014 FERC issued a Notice of Proposed Rulemaking to approve CIP-014-1.
[27] R. 15-06-009.
[28] A.15-07-002.

(1) upgrading conductors to a larger size and (2) increasing circuit voltage to support increased DER penetration. On January 27, 2016, the Commission issued a joint Scoping Memo and Ruling in the DRP proceeding. The scope organizes the proceeding into three concurrent tracks (1) Methodological Issues, (2) Demonstration and Pilot Projects and (3) Policy Issues. The scope envision multiple rulings and Decisions throughout 2016, with additional scoping in 2017. On May 2, 2016, Assigned Commissioner Picker issued a Ruling on the DRP OIR, providing direction on refinements to the Integration Capacity Analysis (ICA), and the Locational Net Benefits Analysis (LNBA). The Ruling authorizes (as modified) the IOUs' related Demonstration Projects A and B, which will demonstrate the ICA and LNBA, respectively. The Ruling provides specific guidance for how the ICA and LNBA will be implemented in the Demos, and also establishes two Working Groups to develop additional recommendations for further refinements to ICA and LNBA, respectively. SCE filed its detailed Implementation Plan on June 16, 2016.

SCE's Grid Modernization (Grid Mod) plan includes acceleration and widespread installation of modern automation and control capabilities on distribution circuits and substations. SCE will update telecommunications vital to its automation efforts, cybersecurity and grid reliability through installing fiber optic cable, wireless communications, and adoption of internet-based protocols. SCE will be transforming its system planning process to consider how DERs can be expanded while supporting reliability on the system. During the Reporting Period, SCE assigned resources to a Grid Mod program management team, performed investment planning activities, and began executing work plans for several work streams. These efforts included developing an integrated project plan, developing business requirements and use cases, initiating procurement activities, performing lab testing of field area network components, and installing distribution automation devices for field pilots.

SCE is committed to supporting state and federal energy policy objectives. Moreover, SCE is committed to making its grid smarter, and maintaining reliability while improving interoperability through new technologies that can accommodate disparate generation at a reasonable price. However, the rate at which SCE is able to study, test, deploy and enable smart grid technology is largely dependent upon the pace and outcome of regulatory processes and proceedings.

## 2.2 Benefits

In this section, SCE provides an estimate of Smart Grid benefits accrued during the reporting period. In identifying and estimating these benefits, SCE leveraged the publicly-available methodology from the U.S. Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability. Using this approach, SCE developed a set of smart grid assets, functions, and benefits, modifying DOE's terminology when necessary to reflect SCE's specific Smart Grid investments. For this annual report, SCE reviewed the status of all Smart Grid projects to determine which assets and functions were in place and producing benefits during the reporting period.

SCE's methodology categorizes benefits into five areas:

1. Operational;
2. Reliability;
3. Demand Response/ Energy Conservation;

4. Environmental; and
5. Other.

Operational benefits consist of reduced and avoided costs of utility operations, including procurement, customer service and T&D costs. Reliability benefits include the societal value of avoided outages and reduced outage duration for all customer classes. Demand Response/Energy Conservation benefits are reflected in measured load impacts from SCE's DR resources. Environmental benefits include avoided greenhouse gas and particulate emissions. Finally, other benefits include areas that are difficult to quantify, such as safety and customer satisfaction. This annual report includes estimates of operational, reliability, and demand response/conservation benefits and provides descriptions of environmental benefits and other benefits.

Estimated benefits for the reporting period are summarized in the table below:

**Estimated Smart Grid Benefits in the Reporting Period**

| Benefit Area | Reporting Period Value |
|---|---|
| Operational Benefits | $9,100,000 |
| Reliability Benefits | $208,900,000 |
| Demand Response/Energy Conservation Benefits | $18,300,000 |
| **TOTAL Estimated Benefits** | **$236,300,000** |

Up until 2014, operational benefits were mainly attributed to those enabled by SCE's Edison SmartConnect program. Edison SmartConnect-related capabilities and systems are now fully integrated into SCE's normal operations. As such, the associated operational benefits have not been recorded in a balancing account since December 2012 and are no longer separately tracked.[29] Therefore, SCE did not include Edison SmartConnect-related operational benefits in this report. Operational benefits shown for the current reporting period are associated with (1) mobile work management tools and processes developed under SCE's Consolidated Mobile Solutions (CMS) project, as described in greater detail in SCE's General Rate Case (GRC) filing; (2) avoided capital expenditure made possible with the Substation Load Information Monitoring System (SLIMS); and (3) avoided procurement cost through conservation voltage reduction (CVR) achieved through deployment of Distribution Volt VAR Control (DVVC) technology.

Reliability benefits come primarily from SCE's circuit automation program, which shortens the amount of time required to restore power to a portion of customers during an outage. This is not a new program, and the benefits accrue from roughly two decades of deployment. As noted in Grid Operations Metric 8, SCE has automated 2,841 of its 4,638 distribution circuits (as of June 30, 2016). For

[29] The settlement agreement approved in D.08-09-039 required that SCE would credit $1.4246 per meter of O&M operational benefits per month during the deployment period, beginning eight months after the meter is reflected in rate base. SCE's operational benefits and capital benefits was included in SCE's ERRA Review Application (A.13-04-001).

the purposes of this report, the benefit was estimated using a Value-of-Service (VOS) reliability model developed by the Lawrence Berkeley National Laboratory. A rough estimate for VOS was based on this model and SCE's specific customer class mix.[30]

Demand Response benefits are associated with commercial DR programs that use interval data, such as those gathered by Edison SmartConnect meters to calculate energy reductions. These programs include the Aggregator Managed Portfolio, Capacity Bidding Program, and Critical Peak Pricing. Participation in these programs can be enhanced, with corresponding benefits to customers, through AutoDR enablement. The MW of these resources are derived from the average ex post load impacts from 2015, which are based on the Load Impact Protocols adopted in D.08-04-050, and the avoided generation capacity value from the DR Cost-Effectiveness Template adopted in D.10-12-024.

Environmental benefits in the form of reduced greenhouse gas emissions have resulted from several of SCE's smart grid initiatives. DVVC, peak demand reduction and energy conservation programs all result in fewer emissions. A reduction in truck usage due to the smart meter program has also produced lower emissions. This report does not provide an estimated value of these benefits. Other benefits resulting from the Smart Grid include a reduction in the risk of safety incidents affecting SCE customers and employees due to the circuit automation program, higher customer satisfaction resulting from improved outage response, and the availability of better customer data and options for managing energy use.

## III. Projects Update

In this section, SCE provides an update regarding its deployment projects and pilot projects described in its July 1, 2011 Smart Grid Deployment Plan. The projects have been grouped in six categories:

1. Customer Empowerment;
2. Distribution Automation/Reliability;
3. Transmission Automation/Reliability;
4. Asset Management & Operational Efficiency;
5. Security; and
6. Integrated & Cross Cutting Systems.

Throughout Section III, the dollar amounts associated with specific projects refer to the total amount spent from July 1, 2015 through June 30, 2016.

### A. Customer Empowerment

SCE's customer empowerment efforts support the Commission's Smart Grid vision which includes customers "who are informed about the Smart Grid and [are able] to use electricity more efficiently and save money."[31] In support of this vision, SCE's customer empowerment efforts will provide customers

[30] The LBNL model was published in 2009. Values have been adjusted to account for inflation between 2009 and 2015-2016.

[31] Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statues of 2009, June 24, 2010.

with accessible information regarding their energy information. Furthermore, SCE continues to develop rates and programs to encourage energy conservation and peak load reductions. SCE provides this energy information while protecting each customer's data privacy, in accordance with the Commission's decision adopting rules to protect the privacy of customer's electric usage data.[32]

Generally, projects in this area develop communication infrastructure, information systems, and energy management services, along with customer-facing tools, services, programs, dynamic rates and outreach capabilities. Furthermore, SCE's efforts will provide automated interval usage information to customer-authorized third parties.

The following discussion provides descriptions and updates regarding the customer empowerment projects.

| Energy Service Provider Interface | $735,000 |
|---|---|
| Description: Pursuant to D.11-07-056, on March 5, 2012, SCE filed an Application (A.12-03-004) proposing a technology platform and infrastructure to enable third parties, when authorized by a customer, to receive that customer's usage data in a secure, automated manner. SCE's proposal uses the data format from the Energy Service Provider Interface (ESPI) national Smart Grid standard (adopted by the North American Energy Standards Board in October 2011). This platform will support customer authentication and authorization, data exchange from SCE to a technically eligible third party, and customer revocation of authorization, and a formal complaint process customers may use in instances when a 3rd party may be considered a "bad actor". (The Commission may order SCE to revoke a third party's access to customer data in appropriate circumstances.) On September 23, 2013, the Commission issued Decision (D.) 13-09-025. That Decision approved SCE's ESPI Application. The Decision authorizes SCE to spend $7.588 million in capital and $1.512 million in O&M through 2014.<br><br>Start/End Date: Implemented in November 2014<br><br>Funding Source: A.12-03-004 | |
| Update:<br>SCE launched Phase 2 of the ESPI platform which provides additional data to designated 3rd parties and scalable to support the increase in 3rd party volume for other proceedings that require data to be transferred to external entities. Phase 2 was launched in February, 2016. | |

| Green Button Initiative | $0 |
|---|---|
| Description: In September 2011, the White House challenged utilities to enable customers to download their usage data in a consistent format by clicking a "Green Button" on the utility's website.<br><br>Start/End Date: Implemented Phase 1 in December 2011, and Phase 2 in December 2012. Phase 3 implemented in 2014. Phase 4 implemented in February 2016. | |

[32] *See* D.11-07-056, Decision Adopting Rules To Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, July 28, 2011.

Funding Source: A.07-07-026, A.07-11-011.[33]

Update:
SCE implemented the Green Button capability in three phases. The first phase, implemented in December 2011, converted the existing usage download button on SCE's MyAccount webpages to use the standard Green Button icon. Phase 2, implemented in December 2012, enables customers to download historical interval usage data using a customer-defined time period (up to 13 months) and gives customers the choice to download data in spreadsheet (CSV) or extensible markup language (XML) format. Phase 3, implemented in November 2014, leverages SCE's ESPI platform (see summary above) for Green Button Connect which expanded customer's ability to share energy usage information and funded via the ESPI application. Phase 4, implemented in February 2016, expanded on SCE's ESPI platform (see summary above) to include additional data elements such as billing history and demand participation.

| 3rd Party Smart Thermostat (PCT) Program | $530,000 |
|---|---|

Description: Although a retail market of smart meter connected Home Area Network (HAN) devices such as smart thermostats didn't emerge as anticipated, Internet connected (usually Wi-Fi) smart thermostats have been gaining traction with consumers. In order to take advantage of these DR capable devices that are already in the homes of many customers, SCE developed a study to partner with some of the leading Internet connected smart thermostat vendors and system providers to enroll these customers in a DR Program and utilize our smart meter interval data. Participating 3rd Party Partners (Nest and EnergyHub) recruited SCE customers with their compatible thermostats into the Save Power Day Program (using the PTR-ET-DLC profile created for this program). Participating customers received the same enabling technology incentive as customers with HAN devices ($1.25 per kWh reduced during events). When events are called, an OpenADR signal is received by the Participating 3rd Party Partners and they implement control strategies (pre-cooling, degree offset, etc.) on customer thermostats to maximize energy savings, while maintaining customer comfort.

Start/End Date: 2013 – 2014 (Study), 2015 – Ongoing (Program)

Funding Source: A.12-12-017 (EM&T Funding), Customer Incentives paid from Save Power Day Program

Update: After successfully running this project as a study for two years with approximately 3,000 customers participating, it was launched as part of the Save Power Day program in June 2015. By the end of June, there were 1,000 participants. As of September 2016, there are approximately 9,000 participants including a third partner in WeatherBug joining in August of 2016. SCE continues to look for new partnerships to expand the base of qualified smart thermostats that support customer choice. SCE has a target of 27,000 participating customers by December 31, 2017.

| Smart Charging PEV Pilot | $3,000 |
|---|---|

Description: The Smart Charging PEV Pilot investigates utilization of the utility's AMI to effectively manage plug-in vehicle loads. Through this pilot, SCE will explore DSM programs that aim to reduce overall system demand along with programs that decrease the impact of vehicle charging on distribution infrastructure such as transformers.

[33] A.07-07-026 funds system updates to provide Green Button functionality (Phase 2 and 3), A.07-11-011 funded costs to modify the existing SCE.com web pages with no functionality changes (Phase 1).

Start/End Date: 2012-2015

Funding Source: A.11-03-003

Update: This project was complete in June 2015. Costs incurred after June 2015 were for final invoices.

| Plug-In Electric Vehicle (PEV) Workplace Charging Pilot | $904,000 |
|---|---|

Description: The PEV Workplace Charging Pilot is deploying 76 electric vehicle chargers with payment and real-time communication functionality at eight SCE facilities to test, monitor, and analyze the impacts of PEV workplace charging. The objectives of the Pilot are to gain a better understanding of consumer behavior related to fee-based charging and DR events, evaluate DR technologies that support non-proprietary charging options and an open communications standard (OpenADR 2.0b), measure system and building load impacts related to plug-in electric vehicle charging, better quantify DR potential of EV charging in the workplace, help determine the balance between DR and customers' needs for EV charging at the workplace, and advise business customers regarding the costs, benefits, and impacts of workplace charging to inform future installation plans at customer properties.

Start/End Date: 2012-2014 (Funding ends in 2014; Pilot activities executed through 2015)

Funding Source: A.11-03-003

Update: Pilot activities were executed from January 1 through December 31, 2015. The SCE pilot tested various pricing and demand response strategies, evaluated consumer behavior related to pricing and DR, implemented a non-charging occupancy fee and its effectiveness on space management control, evaluated DR technologies that support non-proprietary charging options and an open communications standard (OpenADR 2.0b), and measured system and building load impacts related to plug-in electric vehicle charging. SCE spent a total of $903,868 on the project, including PEV charging equipment, construction and installation, network interface, communications, contract services, and other required components. The pilot underspent the authorized budget by $339,257, which was approximately 27% below budget. The SCE Plug-In Electric Vehicle Workplace Charging Pilot Report was served on July 22, 2016. The project is now closed.

| Metering Capital Requirements | $53,000 |
|---|---|

Description: SCE plans to deploy additional Edison SmartConnect (ESC) meters to accommodate customer adoption of time-variant PEV rates through 2014. These meters will leverage the AMI network and part of back office systems deployed to acquire and manage PEV load data.

Start/End Date: 2012-2014

Funding Source: A.10-11-015

Update: During the reporting of July 1, 2015 – June 30, 2016, SCE installed a total of 239 meters for PEV customers. 183 customers selected the Residential TOU-EV-1 rate, 7 selected the Commercial TOU-EV-3 rate and 49 selected the Commercial TOU-EV-4 rate.

| Outage Notifications | $6,585,000 |
|---|---|

This improvement program will use a multi-phased implementation approach to enable a scalable platform that will enable SCE customers to enroll and receive proactive digital maintenance and repair outage notifications.

**ONI Release 1:**
Enable small, unassigned business customers to enroll and receive proactive digital maintenance and repair outage notifications via their channel of choice (i.e., email, voice or text messages). This project is expected to reduce the volume of outage related calls and improve customer outage satisfaction because customers can be better prepared when an outage occurs.

Start/End Date: Sept 2014 to Dec 2015

Funding Source: GRC

Spend July 1, 2015 – June 30, 2016: $542,000

Update:
This project was successfully implemented in production on September 19, 2015.

**ONI Release 2a:**
Enable residential customers to also enroll and receive proactive digital maintenance and repair outage notifications via their channel of choice (e.g., email, voice or text message) and provide customers self-service tools to manage their outage contact information and notification preferences.

Start/End Date: Jan 2015 to May 2016

Funding Source: GRC

Spend July 1, 2015 to June 30, 2016: $6,043,000

Update:
The project was successfully implemented in production on December 29, 2015. Activities completed during this period included design, construction, testing (integration, system, performance and user acceptance), implementation tasks, employee readiness activities such as training and post-implementation technical support.

| DR Systems Enhancements | $1,150,000 |
|---|---|

Description: SCE owns and licenses a variety of systems used to dispatch and measure demand response events. These systems primarily consist of notification systems, load control dispatch systems, event status webpages, customer enrollment and reporting systems, and demand response bidding platforms.

Start/End Date: 2012-2015

Funding Source: A.11-03-003

| |
|---|
| Update: SCE has integrated 6 demand response (DR) programs into the CAISO wholesale market and is participating in a pilot with third party counterparties called Demand Response Auction Mechanism (DRAM). DRAM is utilizing the Rule 24 program/process for third party direct participation with the CAISO. A total of 9 counterparties providing approximately 20 MWs are participating in DRAM where the counterparties are bidding and receiving dispatch instructions directly with the CAISO. SCE also launched for the first time, the DR Mobile app that provides customers a self-service smart phone app for customers to receive alerts when DR events are scheduled, started, ended, or all three. SCE continues to make system enhancements to support self-service. |

## B. Distribution Automation/Reliability

Distribution Automation/Reliability (DAR) projects improve utilities' information and control capabilities for distribution systems. These capabilities may be used to address the complexities associated with integrating distributed energy resources and electric vehicles, advanced outage management, and/or volt/VAR control. DAR projects provide the ability to safely and reliably incorporate high penetrations of distributed energy resources by mitigating voltage fluctuations resulting from intermittent power generation. These projects would also provide the ability to safely and reliably incorporate the increasing load of charging electric vehicles (EV).

DAR would detect and isolate faults when they occur, immediately restore service to customers as soon as possible and provide information to customers about outages in real-time. "Self-healing" circuits will reduce the number of customers affected by system disturbances and enable faster service restoration. DAR would also provide optimization of voltage and reactive power on the system to enhance power quality and decrease energy consumption.

DAR helps enable electricity markets to flourish and helps deliver a Smart Grid that has the infrastructure and policies necessary to enable and support the integration of demand response, energy efficiency, distributed generation and energy storage.

| Geographical Information System (GIS) | $4,998,000 |
|---|---|
| Description: The Geographical Information System project will consolidate the physical, electrical, and spatial features of all Transmission & Distribution assets and allow end-users to access this information from one reliable source. This comprehensive system will provide the ability to integrate multiple databases, both internal and external to Transmission & Distribution (T&D), and help meet safety, reliability, and compliance obligations. It will include detailed asset information, electrically linked information, and landbase information from such sources as the Bureau of Land Management and FEMA. This information will be used by business operations teams and SCE systems to gain operational effectiveness.<br><br>Start/End Date: 2010-2015<br><br>Funding Source: GRC | |
| Update: During the last half of 2015, the project team focused on the final deliverables for the cGIS project. Deliverables for this period included: Implementation of the Consolidated Data Store (CDS), a major component of Release 3b; deployment of a series of stabilization releases to resolve defects | |

identified through system and user testing; multiple data mop ups applied in the production environment; data migration and implementation of Cutover 5 and 6 data sets; implementation of Transmission FSA functionality for Real Properties; uplift of land base data to September 2015; completion of UG cross-section implementation; implementation of SCEGeoView refresh on new Java platform; and conducted knowledge transfer with MSPs for operational transition.

| Consolidated Mobile Solutions | $6,257,000 |
|---|---|

Description: Consolidated Mobile Solutions (CMS) will enable field personnel, system operators, and office workers to share real-time information related to software systems. The maps from these software systems will enhance SCE's safety, improve outage responsiveness, and contribute to SCE meeting its compliance obligations. CMS will reduce lost time, enabling the existing work force to be more productive.

Start/End Date: 2010-2017

Funding Source: GRC

Update: The CMS release for Grid Operations Substation Operators and Substation Construction & Maintenance has been tested, implemented on July 9, 2015, and deployment/user training was completed on March 3, 2016. A third CMS release was tested, implemented on April 22, 2016, and deployment to Grid Operations Troubleman started May 2, 2016. Deployment and stabilization of the third CMS release is in progress with a target completion of Q2 2017.

| Distribution Management System | $5,021,000 |
|---|---|

Description: Distribution Management System (DMS) is the centralized computing system that allows SCE to gather data from various automated distribution devices and facilitates automated operation and control of the distribution system. DMS will replace SCE's current Distribution Control and Monitoring System, which is obsolete. DMS will provide an improved, comprehensive solution, intended for long-term use, to assist Grid Operations' System Operators in responding to routine and emergency field conditions.

Start/End Date: 2010-2016

Funding Source: GRC

Update: For DMS Phase 2, SCE successfully completed delivery of "Distribution Volt/Var Control" (DVVC) application in December 2013. For DMS Phase 3, SCE successfully deployed "Signature" advanced applications (Distribution Power Flow/Distribution State Estimator, Dispatch Training Simulator, and Study Cases) in November 2015. For "Switching" advanced applications (Fault Detection Isolation and Restoration, Contingency Load Transfer/Restore) and IVVC (Integrated Volt Var control) the project team has completed Design, Build, Acceptance testing and implementation is scheduled in July 2016. Both Signature & Switching advanced applications will be rolled out to end users by December 2016.

| Circuit Automation | $3,933,000 |
|---|---|

Description: The primary purpose of SCE's Circuit Automation Program is to automatically restore power to customers after outages caused by faults. In providing this service, the Circuit Automation

helps minimize the impact on customers of outages that occur in the ordinary course of business. The capabilities provided by the Circuit Automation Program are consistent with basic service provided by most utilities in this country.

Start/End Date: 2010-Ongoing

Funding Source: GRC

Update: In order to maintain a reliable system, SCE has integrated remote control switches within its distribution system. Between July 1, 2015 and June 30, 2016, SCE installed 188 remote control switches and spent $3,933,000.

SCE has recognized that automating distribution circuits can help improve overall system performance and increase the reliability of the system.

| Capacitor Automation | $2,033,000 |
|---|---|

Description: SCE's Capacitor Automation program automates existing manual capacitor controls and upgrades obsolete, first-generation automation equipment. Capacitor controls are used to remotely operate switched capacitor banks installed on the distribution system to provide voltage and VAR support. Without capacitor banks, the voltage supplied to SCE customers would drop to levels that can damage the customers' equipment or appliances, and present safety hazards. Automating the control of these capacitor banks allows SCE to remotely monitor and control the operation of these devices, rather than sending a person to operate the device manually in the field.

Start/End Date: 2011-Ongoing

Funding Source: GRC

Update: As part of its Capacitor Automation program, SCE is continuously deploying fully programmable capacitor controls (PCCs). By automating capacitor controls, SCE is replacing failing capacitor controls while improving voltage and Volt-Ampere Reactive (VAR) control. Additionally, SCE is adding the capability to remotely check and monitor capacitor bank operating status. During the July 1, 2015 to June 30, 2016 time frame, SCE installed approximately 595 PCC's and spent $2,033,000.

| Distribution Energy Storage Integration (DESI) Program | $55,000 |
|---|---|

Description: The DESI program includes the deployment of several energy storage systems to provide value to local distribution circuits. The first project installed a battery energy storage system (BESS) with an active power rating between 2.0 MW and 4.0 MW, and usable stored energy capacity between 3.5 MWh and 4.0 MWh in a pilot deployment to support a primary distribution circuit that has problematic loading characteristics. This project measures the operating parameters of the BESS and determines the values created by the BESS. The first project plan and "lessons learned" are used as guidance for subsequent pilot deployments.

Start/End Date: 2013 – 2017

Funding Source: GRC

Update: The first DESI system (DESI 1) sized at 2.4MW and 3.9MWh reached commissioning & final completion. DESI 1 is in-service supporting the Scarlet 12 kV distribution circuit out of Orange Substation, located in the City of Orange, California. This circuit feeds several large commercial and industrial customers, and sees intermittent, multi-megawatt spikes in demand as part of the customers' load profiles (manufacturing and testing operations). DESI 1 constantly monitors circuit and some customer loads, and discharges to dynamically limit power to a predefined threshold. This defers the need for costly distribution network upgrades and increases reliability by helping ensure the circuit can meet summertime peaks. The Advanced Energy Storage team continues to monitor and verify DESI 1 performance and periodically conducts performance tests to measure battery health.

The DESI 2 project is in the execution phase. This 2MW, 4MWh BESS will be constructed on an SCE owned transmission right-of-way in the City of Santa Ana, and will support the Integrated Grid Pilot (IGP) program. The system's planned operating date is 6/1/2017. We expect the PO for the battery vendor to be issued during the week of 7/18/2016. Preliminary civil engineering has begun conceptual design work. Immediate next steps are: (1) meet with the City of Santa Ana by 8/5/16 to provide a project overview and determine the city's position on permit requirements; (2) conduct a project kick-off meeting by 8/19/2016 with the vendor and civil engineering to establish equipment layout and project milestones.

The DESI 3 project (formerly known as DOS) includes two 500kW, 500kWh battery systems that will support IGP. The construction sites are not yet identified; the Real Properties team is working to locate appropriate sites. The expected operating date for DESI 3 is 10/1/2017.

| Outage Management System | $2,874,000 |
|---|---|

Description: The Outage Management System (OMS) Refresh will deliver a system with the vendor's most current software and hardware in order to improve the level of system availability, usability, and reliability required to support the needs of our business organizations and customers, as well as provide strategic smart grid-based enhancements to the system. For example, the Refresh will provide a range of enhanced smart meter functionality including: integrated ability to perform an instantaneous voltage read on a customer's meter, including groups of meters; and, the ability to energize outage locations based on a percentage of Power Restoration Notifications received from the smart meters.

The Refresh Project will be delivered in three releases:

- Technology Release – Implementation of the COTS package to the newest version 6.5
- Network Connectivity Model Release– Implementation of an end-to-end outage modeling through the use of a Transmission, Sub-Transmission, and Substation As-Is Connectivity Model
- Enhancement Release – Implementation of a series of enhancements that take advantage of the new version's capabilities and additional smart meter integration

Start/End Date: 2014-2017

Funding Source: GRC

Update: The Technology release is in the final stages of testing as of Q2 2016, and is scheduled to be rolled out in Q4 2016. The Trans-Sub Model is currently in planning phase. Testing for the Enhancement Release will commence in Q4 2016.

| Substation Load Information Monitoring System (SLIMS) | $800,000 |
|---|---|

Description: The primary purpose of the program is to have a remote unit, known as SLIMS, that would provide information on an available system which will be used for monitoring transformer bank, bus tie circuit breakers, and circuit phase current levels at existing SCE substations that do not have telemetry. SLIMS will be using the existing current transformer at the substations to record the information and then send the information through our wireless network to our Device Management System (DMS), our Energy Management System (EMS), and lastly our eDNA data historian. Once stored in our data historian databases, the data can be viewed, trended, and otherwise manipulated via the RTView software application. Having these units at substation that previously had no available telemetry allows our Engineering teams and Grid Operations teams to remotely monitor the load of either the transformer banks, bus tie circuit breakers, or circuit phase levels.

Start/End Date: July 2015 - April 2016

Funding Source: Capital

Update: The program concluded with the last device being installed on April 6th, 2016. A total of 20 SLIMS units were installed between July 1st, 2015 and June 30, 2016. These units were also end point tested to verify that accurate readings were coming in and recorded by SCE historian databases. Approximately $800,000 was spent to install and end point test 20 units between stated timeframes.

| Distribution Volt/Var Control (DVVC) | $245,000 |
|---|---|

Description: The primary purpose of DVVC is to centralize control of the field and substation capacitors, in order to coordinate and optimize voltage and VARs across all circuits fed by a substation. Supervisory-controlled distribution substation capacitors and existing standard automated distribution field capacitors on distribution circuits are leveraged to reduce energy consumption, while maintaining overall customer service voltage requirements. Deploying DVVC at SCE as a grid integration solution will optimize voltage levels on the distribution system, reducing excess voltage, which results in avoided energy procurement and capacity costs, while not compromising the safety and reliability of service. SCE estimates these avoided energy procurement and capacity costs to provide a 1% actual savings in energy costs for customers per 1% reduction in voltage.

Start/End Date: November 2015 - Ongoing

Funding Source: Capital as part of 2012 and 2015 GRC

Update: DVVC is currently in the deployment phase. DVVC was approved for deployment in June 2015. Processes, procedures, and training was developed and executed for the remainder of 2015 resulting in several substations implemented. The implementation phase is currently targeting 100 substations in 2016.

| Equipment Demonstration and Evaluation Facility (EDEF) | $9,752,000 |
|---|---|

Description:
Equipment Demonstration and Evaluation Facility (EDEF) is a new 12kV test circuit which allows SCE engineers to perform evaluations of largely unproven emerging technologies on energized high-voltage equipment and distribution circuits under real world conditions to determine the likelihood of operational successes and failures prior to deployment. Testing capabilities include; simulating various fault magnitude and conditions on the 12kV distribution circuits, performing simultaneous testing of up to 10 automated fault interrupting devices including overhead, padmount and underground construction/installation methods validation, and distribution and substations automation. The development and construction of an SCE owned energized EDEF will improve both engineering and power delivery processes by providing insight into equipment capabilities and operations.
There is increasing pressure to replace and upgrade infrastructure, coupled with the uncertainty around emerging technologies. Thus it is increasingly imperative to validate equipment performance in an energized facility prior to piloting.

Start/End Date: Inception: December 2015

Funding Source: Capital

Update:
Circuit construction was completed and circuit was energized in December 2016. Control building is projected to be completed by the end of Q1 of 2017.
New substation circuit breaker was designed and installed for the new 12kV circuit. Civil and electrical design and construction of the circuit was completed. Design of the control building is completed. Permitting efforts are expected to be done by October 2016.

## C. Transmission Automation/ Reliability

Transmission Automation/Reliability (TAR) includes projects that provide wide-area monitoring, protection and control to enhance the resiliency of the transmission system. TAR also includes projects to provide the ability to safely and reliably incorporate utility-sized intermittent power generation such as centralized solar and wind energy. TAR projects help mitigate voltage fluctuations resulting from integrating intermittent resources.

The wide-area capabilities of TAR provide the ability to monitor bulk power system conditions, including but not limited to voltage, current, frequency and phase angle, across the IOU geographic area in near real-time. This functionality provides system operators with current information about emerging threats to transmission system stability, enabling preventive action to avoid wide-scale black outs. In addition, the wide-area capabilities of TAR also include projects for coordination of high-speed communicating transmission protection equipment that detect conditions in the transmission systems and automatically respond to stabilize the system.

| PHASOR | $67,000 |
|---|---|
| Description: In collaboration with the Western Electricity Coordination Council and for use by Reliability Coordinators, the Phasor system will enable SCE to collect, store, verify, and share Phasor Measurement Unit information about the status and health of the grid, at millisecond intervals. The Phasor system will also serve to accommodate compliance obligations, as part of SCE's commitment to participate in the Western Interconnect Synchro-phasor Program.<br><br>Start/End Date: 2011-2014<br><br>Funding Source: GRC | |
| Update: The Phasor system continues to send synchrophasor data to SCE's Grid Control Center, WECC, and other participating utilities. Phasor Measurement Units are installed in twelve substations. The final payment regarding backup and recovery change request for Phasor project was made in 2015. | |

| Centralized Remedial Action Schemes (CRAS) | $ 8,663,000 |
|---|---|
| Description: Centralized Remedial Action Scheme (CRAS) is needed because current logic controllers in field-based "stand-alone" Remedial Action Schemes (RASs) are limited and cannot cope well with increasing interconnection complexities. CRAS improves architecture, management, oversight, and effectiveness of remedial action. Centralized Remedial Action Scheme reduces tripping of generation and/or shedding of load as needed.<br><br>Start/End Date: 2011-2016<br><br>Funding Source: GRC | |
| Update: The CRAS Project completed with two stand-alone RASs incorporated and was used and useful April 7th, 2016. Currently the project is ramping down and in stabilization phase and will close financially in 2016. CRAS is performing as designed and there are no major anomalies to date. | |

## D. Asset Management & Operational Efficiency

Asset Management & Operational Efficiency (AMOE) enhances monitoring, operating and optimization capabilities to achieve more efficient grid operations and improve asset management. AMOE includes projects that will allow SCE to manage the maintenance and replacement of energy infrastructure based on the health of the equipment versus a time-based approach. This functionality will prevent failures of critical energy infrastructure as well as manage costs associated with maintaining and replacing equipment.

| Online Transformer Monitoring | $1,828,000 |
|---|---|
| Description: Field devices will collect real-time information about the health of transmission and distribution system infrastructure. The particular field devices that enable equipment monitoring depend on the equipment targeted for monitoring. SCE uses Dissolved Gas Analysis (DGA) technology and bushing monitoring devices for bulk power transformers. SCE has targeted a total of 68 500-kV | |

(AA) and 137 230-kV (A) transformer banks at substations to deploy online transformer monitors. As part of its Online Transformer Monitoring Project, SCE plans to deploy DGA technology and bushing monitoring devices on one AA substation and four A substations per year from 2011 through 2014.

This program will improve transformer reliability, reduce failure impacts, identify units in urgent need of repair or replacement, realize the full transformer useful life, and a substantial reduction of overall transformer operating risks. In addition, this pilot will provide substation operators with information regarding the condition of transformers within their substation, therefore giving them the ability to quickly de-energize a transformer showing signs of trouble. This results in a positive impact to customers due to early identification of potential Bulk Electric System Transformer Failures, preventing collateral damage of an unidentified failure.

Start/End Date: 2009 - 2016

Funding Source: Capital

Update: This year's testing of data from RTU, to the back office and to the outside vendor was successful. However, due to technical challenges with the vendors, there are a few minor issues needing resolution before we can deploy to the remaining sub-stations. The target completion of the pilot is Q3 of 2016.

## E. Security

Physical and cybersecurity protection of the electric grid is essential and becomes more important as the Smart Grid is deployed. The communications and control systems that enable Smart Grid capabilities have the potential to increase the reliability risks of Smart Grid deployments if they are not properly secured. The Security program includes a comprehensive set of capabilities to address the increased physical and cybersecurity requirements associated with the development, implementation, operation and management of Smart Grid systems and edge devices. These projects would place and execute security throughout the network to resist attack, manage compliance and risk, and support security from the physical to application layers.

| Common Cybersecurity Services | $6,311,000 |
|---|---|

Description: The Common Cybersecurity Services (CCS) has transferred advanced cyber security technologies from the defense and intelligence industry to secure our Smart Grid implementations. CCS is currently deployed and in production use in 27 bulk electric substations (BES). CCS is designed to implement security mechanisms to enforce confidentiality integrity and availability in the form of security services and policies that protect electronic information, communication and control systems necessary for the management, operation, and protection of the SCE Smart Grid System of Systems (SoS) as well as comply with key provisions of NERC CIP version 5.

Start/End Date: CCS development and initial deployment is scheduled to end in 2016. After 2016, CCS products will be procured and deployed as regular standard products.

Funding Source: GRC

Update: During the reporting period, the following was completed:

- System Acceptance Test
- Commissioning and 1000 hours tests in a production BES substation
- Implementation of the Security Operations Center for the grid (staffing and training)
- Production commissioning of CCS (including keying and go live)
- Full CCS operations
- Installation and operation in CCS in 27 total BES substations.

## F. Integrated & Cross Cutting Systems

Integrated and cross-cutting systems refer to projects that support multiple Smart Grid domains, such as grid communications, application platforms, data management and analytics, advanced technology testing, and workforce development/technology training. An integrated approach helps to ensure that investments are managed efficiently while creating the platform to deliver a stream of benefits across utility operations and to customers.

Integrated communications systems provide solutions to connect and enable sensors, metering, maintenance, and grid asset control networks. In the mid-to-long term, integrated and cross cutting systems will enable information exchange with the utility, service partners and customers using secure networks. Data management and analytics projects will improve SCE's ability to utilize new streams of data from transmission and distribution automation and Smart Meters for improved operations, planning, asset management, and enhanced services for customers.

Advanced technology testing and standards certification are a foundational capability for the utilities to evaluate new devices from vendors and test them in a demonstration environment prior to deployment onto the electric system. This reduces the risks associated with new technology projects, and helps the utilities maximize technology performance and interoperability.

Workforce development and advanced technology training enable the successful deployment of new technologies, helping ensure that the utilities' workforces are prepared to make use of new technologies and tools, maximizing the value of these technology investments.

| Substation Automation Integration IEC 61850 | $12,000 |
|---|---|

Description: To replace the HMI and ABB DPU/TPU protective relays with the latest replacements under the Substation Infrastructure Replacement (IR) program. Dalton Substation will serve as the pilot substation for the Substation Automation System 3 (SA3) Hybrid, which will accomplish the primary goal of this project.

The project will ultimately make Dalton an SA3 substation, but will allow it to take place with backwards compatibility to legacy equipment (DPU/TPU relays). Each DPU/TPU relay can be replaced one at a time with a modern IEC 61850 compliant relay, in the same relay slot on the existing relay rack. The advantage of the backwards compatibility allows many of the relay racks, test switches, and significant portions of wiring to be re-used.

Start/End Date: 2013-2015

Funding Source: GRC

Update: This project was complete in June of 2015 and SA-3 was published as the new Distribution Standard in July 2016. From July 1, 2015 to June 30, 2016, the project incurred $12,456 in cost. The bulk of the costs incurred represent the final invoice from DC Systems Inc. at the end of the Fiscal Year, as required by their contract.

| Advanced Technology Fenwick Labs | $2,306,000 |
|---|---|

Description: Southern California Edison (SCE) continues to implement smart grid technologies to create a smarter, safer and more reliable energy future. This grid of the future will provide customers with advanced tools and resources that enable informed and responsible energy consumption, and better serve customers by achieving an appropriate balance between energy policy and safety as well as reliability and affordability. Achieving this balance is a challenge, as the electric grid is an immense and complex system. To help ensure proper operation, rigorous technology evaluation must take place in a controlled environment before smart grid technologies are deployed on the grid. Thus, SCE developed the Advanced Technology Fenwick Labs to provide an integrated platform for evaluating the safety and operability of Smart Grid technologies without impacting customers by testing on distribution circuits or other equipment.

Start/End Date: 2011 - N/A

Funding Source: GRC

Update: In order to continue providing a controlled testing environment, SCE continues to make the necessary enhancements to the Advanced Technology Fenwick Labs facility and its associated test equipment. This allows SCE to effectively and rigorously evaluate smart grid technologies safely and without impacting the grid or its customers. The following updates were made to the SCE Advanced Technology Fenwick Labs during the reporting period:

**Communications and Computing Lab:** In 2015, a more robust uninterruptible power supply (UPS) system was purchased to support the expanded Advanced Technology lab network. This system was installed in the first quarter of 2016 with a total purchase and installation price of $290,000. In addition to the UPS, the lab network underwent an expansion in 2015 at a cost of $464,000 to support the growing networking and increasing data handling requirements for smart grid analytics.

**Substation Automation Lab:** In 2015, $51,000 in relays and an additional power system simulator for $45,000 were purchased to expand abilities to simulate larger substations. In preparation for transmission substation simulations, two IEC61850 capable multifunction meters were purchased totaling $5,000. Also to support transmission substation simulations, a communications test set that provides recording capabilities and logic necessary for lab testing and troubleshooting was purchased for $8,300.

**Distributed Energy Resources Lab:** To support the testing of smart inverters, $8,500 was spent on upgrades to increase grid simulator capabilities.

**Controls Lab:** In 2015, $247,000 was spent on the development and evaluation of a controls platform for integration of distributed energy resources to improve grid reliability.

**Power Systems Lab:** A new 230Kv circuit test environment simulation was set up to mirror the field to allow for end to end testing. This setup required the purchase of substation relays, upgrades to the existing real-time digital simulator and cabinets to house the relays at a cost of $580,000.

**Miscellaneous Support equipment and tools:** Various tools and equipment purchases occurred to support the operations of the labs and new test setups. The total purchases in this category are $607,000, which includes racks to mount equipment, facility improvements for interconnection of the new equipment, networking improvements, and acoustical improvements to the lab environment.

| Distribution System Efficiency Enhancement Project (DSEEP) | $4,011,000 |
|---|---|

Description: The Distribution System Efficiency Enhancement Program (DSEEP) consists of servicing and expanding the NETCOMM wireless communication system. The NETCOMM system provides the radio communication infrastructure to remotely monitor and control SCE's distribution automation devices. These automation devices include all of the devices deployed under the Circuit Automation and Capacitor Automation programs described above.

Start/End Date: Ongoing

Funding Source: GRC

Update: SCE added 1,970 distribution automation devices from July 2015 to June 2016. Additionally, SCE added 38 infrastructure radios, extending communication to the new devices. These new devices include Radio Controlled Switches, New Capacitor Banks, and Automated Reclosers. The program also maintained radio infrastructure to existing devices. Maintenance efforts supported 406 automation device replacements, and 55 packet radios to maintain network performance levels. The maintenance activities also included replacing 518 end-of-life battery-backed radios.

| Grid2 | $4,260,000 |
|---|---|

Description: The Grid2 project is an initiative to build a single, scalable, secure and cost-effective IP network to provide support for all current and future grid applications using virtualization. This network is a type of service provider network which is capable of transporting and segmenting data for a variety of applications.

Start/End Date: 2012-2016

Funding Source: GRC

Update: Over the course of the last 12 months the team has been working to build out a redundant core of the Grid2 network, enhance communications between the Control Centers, deploy additional equipment in the Grid2 lab as well as build an environment to securely connect shared SCE sites to the Grid2 network. Additionally, we have been extending fiber to SCE substations and evaluating packet based microwave technology.

| Charge Ready Program | $493,000 |
|---|---|
| Description: The Charge Ready Program is an initiative to deploy electric vehicle (EV) charging stations at long-dwell site locations where EVs are parked for four hours or more (including workplace, multi-family dwellings, fleet parking, and destination centers). In addition, SCE also conducts market education to develop awareness about EVs and the benefits of fueling from the grid.<br><br>Start/End Date: 2016/ Ongoing<br><br>Funding Source: Application/balancing account | |
| Update:<br>SCE launched the Phase 1/Pilot of the Charge Ready Program in May 2016 after receiving approval from the Commission in April 2016. As of June 30, SCE had received 193 applications to the Pilot and was in the process of launching its market education efforts. | |

## IV. Customer Engagement Timeline

The common template for the Annual Reports, which was adopted by D.13-07-024 and initially proposed by Commission Staff in the March 2012 workshop report, requires the IOUs to include a customer roadmap that provides an overview of the IOU's customer engagement plan. SCE included its initial customer roadmap as Section IV of its 2012 Annual Report. The general outreach approach and strategy presented in the 2012 Annual Report has not changed and is not repeated in this report.

The common template requires the IOUs to include the following information in their Smart Grid Annual Reports: (1) a timeline that connects specific projects with specific marketing and outreach efforts, and (2) specific steps to overcome roadblocks, as identified in the workshops. As described in the 2012 Annual Report, SCE expanded on the sample template by recognizing that certain ME&O efforts are not confined to a single calendar year. Consistent with this approach, SCE provides its Customer Engagement Timeline (see figure below), which presents the appropriate initiatives provided in SCE's Customer Engagement Baseline and Roadmap Summary, and identifies the anticipated Smart Grid related ME&O efforts by year. Consistent with its GRC and DR application cycles, SCE provides such information from 2012 to 2017.

***Customer Engagement Timeline (2012-2017)***

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| **Customer Premise Devices** | | | | | | |
| A. Near Real-Time Usage (HAN)* | | X | X | X | X | X |
| **Online Tools** | | | | | | |
| B. Integrated Audit Tool | X | X | | X | X | X |
| C. Web Presentment Tools* | X | X | X | X | | |
| D. Budget Assistant* | X | X | X | X | | |
| E. Green Button Download My Data | X | X | X | | | |
| F. Green Button Connect My Data | | X | X | X | X | |
| G. Mobile-Optimized Outage Center | X | X | X | X | | |
| **Rates and Programs** | | | | | | |
| H. Save Power Day (PTR) | X | X | X | X | | |
| I. PEV Time-of-Use Rates* | X | X | X | X | X | X |
| J. Residential TOU Rates | | | | X | X | X |

*X = SCE or third party ME&O to support this initiative.*

** SCE will market these program / services through its Offer Management Approach, as described in SCE's 2012 Annual Report.*

The common template also requires the IOUs to provide the following information for each identified Smart Grid related ME&O effort:

- Project description;
- Target audience;
- Sample message;
- Source of message;
- Current road blocks; and
- Strategies to overcome roadblocks.

Thus, as it did in the 2013 Annual Report, for each initiative identified in the above figure, SCE has provided such information in Appendix 1 of this report. In addition to discussing the initiatives identified above, Appendix 1 also includes SCE's customer engagement activities for certain pilots and demonstration projects and for conceptual projects.

## V. Risks

In this section, SCE provides an overview of activities related to helping ensure grid reliability for its customers. The sections below provide an overview of the motivation behind developing open standards for Smart Grid infrastructure and cybersecurity investments and solutions. The motivation behind developing a smarter grid and its associated architecture remains consistent with those presented in SCE's 2011 Smart Grid Deployment Plan (A.11-07-001) and approved in D.13-07-024.

### A. Introduction – Smart Grid Motivation

Progressive policy objectives and customer adoption spur SCE's efforts to integrate renewable resources, distributed generation, electric transportation, and energy storage. A thoughtfully designed, smarter electric grid will allow SCE to utilize new energy technologies to monitor, predict, and control the increasing adoption of renewable and distributed resources. The primary risks associated with the introduction of emerging technologies in general are: 1) Technology Maturity; 2) Market Structure/Regulatory Uncertainty; and 3) People/Process Change Management.

The technology evolution challenge is well-understood and can be characterized through the following areas:

1) Technology evolution causing obsolescence in existing infrastructure
2) New technology adoption becoming obsolete prior to the asset's complete lifecycle
3) New technology adopted to interface to other technologies that become obsolete
4) Misalignment of depreciation rules with technology lifecycle
5) General misalignment with depreciation rules and revenue requirements (i.e. discontinuous impacts on rates with accelerated depreciation)

The market and regulatory uncertainty present another host of challenges, including the following:

1) Market structure uncertainty creating uncertainty on what entity should build and own the infrastructure, resulting in reduced infrastructure investment on an overall basis
2) Market structure uncertainty creating uncertainty in the rate of technology adoption and infrastructure required
3) Regulatory input to the market structure possibly sub-optimizing the market, and creating misalignment with infrastructure requirements and ownership
4) Customer and third parties' (e.g. aggregators') interaction and acceptance of market will evolve and influence market success/failure

The people and process issues include:

1) Significant changes in process and impacts on roles and responsibilities

2) Diverse perspectives (e.g. utilities, customers, regulators, 3rd parties) will require significant consensus building, and delays may create sub-optimal results

3) Resistance to change from perceived or real failures in market/regulatory solutions, creating a more generalized perception of resistance to change

These risks are mitigated and challenges managed through mechanisms like comprehensively testing emerging technologies in lab environments, using demonstration projects to further test technologies and concepts, and carefully structuring implementations of deployable technologies on the grid. The smarter grid envisioned through this deployment plan requires not only consensus on roadmaps and projects, but also fact-based results from realistic and accurate simulations, laboratory testing, pilot demonstrations, and thoughtful implementations of emerging, smart technologies.

The Distribution Resource Plan process is working to encourage a thorough understanding across multiple stakeholders of the challenges and opportunities of high penetration of renewable and distributed energy resources. The demonstration projects proposed and the associated workshops associated with each demonstration project are mitigating opportunities to develop and deploy a modern infrastructure that attempts to optimize the technology decisions made by the utility as well as customers and resource providers. This collaborative effort and early demonstration of key technologies and processes is critical to informing stakeholders and reaching consensus.

## B. Smart Grid Architecture Challenges

We are shifting today's electric grid from a system that is robust and reliable largely due to the basic laws of physics to a smarter electric grid that increasingly relies on technology to maintain stability and achieve a higher level of resilience. To do this, we must obtain an in-depth understanding of systems theory, power systems, computer science and utility operations. Applying these diverse and specialized disciplines in a coordinated approach that yields cost-efficient, manageable, and reliable solutions requires a clear Smart Grid strategy and architecture approach. The key architecture challenge in evolving the electric grid is to help ensure that introducing automation, connectivity and advanced control systems does not create a system that is too complex or too fragile to manage.

Utilities have tended to rely heavily on highly customized solutions that were organized in a silo of proprietary devices, communications, security, configuration and control systems. This approach is commonly known as "security by obscurity." While this approach was efficient for each individual project with clear scope, schedule and cost objectives it results in a higher cost of maintenance and operations and a higher cost of new capabilities because each silo requires integration. If this approach is applied to grid modernization, the result will be a costly and fragile infrastructure that will impact grid reliability. An integrated approach to systems design, coupled with a common services architecture, is required to overcome this architecture challenge.

## C. Cost-Efficient Smart Grid Design

A reasonably cost-efficient approach to deploying Smart Grid capabilities involves organizing technologies and systems into loosely coupled, standards-based layers capable of supporting common services. A Smart Grid common services architecture delivers the capability for any device in the

forward deployed networks to access common services (such as cybersecurity, device management, network monitoring, etc.) in SCE's control centers. The common services architecture supports multi-vendor interoperability by enforcing standards across the architecture and drives implementation and operational costs down by simplifying the systems design. We simplify systems design by eliminating silos that extend from the application layer through the security, communications and device layers.

Over the past several years, SCE has been working to develop a Common Cybersecurity Service, based on the premise that the level of automation and connectivity that is being introduced through grid modernization efforts requires military-grade cybersecurity to help ensure grid reliability in the face of increased cyber vulnerabilities introduced by new Smart Grid technologies.

## D. Standards Overview

SCE has a long history of supporting the development of open standards. SCE recognizes that standardization of key areas can yield benefits to both consumers and service providers. Such benefits include enabling market innovation, reducing complexity, reducing equipment costs and protecting investments necessary to help ensure long term deployments. In addition, participating in standards development gives SCE the ability to prevent vendor "lock-ins" and to foster interoperability with legacy systems. Furthermore, SCE's participation in standards development brings extensive technical knowledge and experience along with utility credibility to the relevant working groups and organizations. SCE's approach to standards and interoperability includes supporting the development of the actual standard, laboratory testing and evaluation, and field trials.

SCE has identified over 70 standards of interest for Smart Grid development. Of these 70 standards, SCE's Advanced Technology organization is currently supporting the development of over 40 standards. These standards are found in specific areas, including system integration/architecture, data formats, communications, security and electrical interconnections/power quality. Many of these standards are being developed by the Institute of Electrical and Electronics Engineers (IEEE) and the International Electrotechnical Commission (IEC). SCE is or has been involved in the development of standards, testing and verification within these organizations, including:

- IEEE P2030: Guide for Smart Grid Interoperability
- IEEE1547: Distributed Energy Resource Interconnection Standard
- IEC 61850: Substation Automation
- IEC 62351: Power systems management and associated information exchange – Data and communications security
- Rule 21: California IOUs Standard to interconnect of distributed generation
- UL1741: Standard that mainly fallow IEEE 1547 but will incorporate a revision to California Rule 21

It is important to acknowledge that extensive involvement in standards development can pose many challenges to an organization. Such challenges include finding internal resources, both human and financial, to support the relatively long and exhaustive process. Standards often require fairly senior staff that is experienced and knowledgeable. Senior staff is then under significant pressure to not only

support important core job functions but to also support the standards development. From a financial perspective, organizations not only need to finance staff for participating in standards development and paying applicable fees, but additionally some organizations resort to expensive consultants to fill in gaps when full time staff is severely impacted and/or unavailable. Specifically, participation in IEC standards can be rather difficult for regional electrical utilities to justify travel overseas.

Since 2013 SCE has been reducing its involvement with many smart grid standards. The reduction in participation stems from the fact that many of the standards that used to be infant or nonexistent are now mature enough be demonstrated. Standards like Smart Energy 2.0, OpenADE and OpenADR2.0 are available and ready for use. SCE helped drive and mature standards during the early days of smart grid technology and now has made a strategic decision to continue supporting the industry by focusing on the application and demonstration of these standards through continued involvement in some industry alliances (such as the OpenADR Alliance) and by requiring open standards for program participation. SCE also still maintains some involvement in key standards groups including IEEE, SAE and IEC.

SCE has been testing U.S and European Solar PV Inverters where it acquired extensive knowledge of their performance. Furthermore, this testing has provided assessment of what advanced inverter features can make an impact and provide grid support during higher penetration of these resources. SCE with sponsorship of DOE has been installing power quality monitors in the distribution system to gather actual field data in order to propose standards that will be meaningful and provide actual benefits to the grid. Since 2013, SCE has been proactively involved in California Rule 21 Smart Inverter Working Group. This standard created the first set of advanced features of solar PV inverter in the U.S. These features are meant to reduce their effects of higher penetrations in the grid. SCE has been also strongly involved with the IEEE1547 where it has been providing technical support to this standard. The technical support includes field knowledge of distribution circuits' performance, laboratory testing knowledge on how solar PV inverters perform, and what advanced features would be beneficial to the U.S. grid. SCE has published over 30 reports and research papers (DOE, IEEE, etc.) on solar PV inverters that have been used to help develop standards.

### *1. NIST Smart Grid Standards Coordination*

The 2007 Energy Independence and Security Act (EISA) gave the National Institute of Standards and Technology (NIST) the "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems." To achieve this mandate, NIST devised a three-phased approach to identify an initial set of standards, while providing a robust process for continued development and implementation of standards as needs and opportunities arise and as technology advances.

In 2009, NIST created the Smart Grid Interoperability Panel (SGIP) as a public/private partnership to coordinate the identification and development of Smart Grid standards. Since then, the SGIP has grown to an organization representing twenty-two stakeholder categories and over 770 member organizations ranging from electric utilities to consumer electronics providers. One of the obligations of the SGIP is to

produce and maintain a Catalog of Standards that could be used for developing and deploying a robust and interoperable Smart Grid.[34]

SCE is a strong supporter of the NIST/SGIP standards process. Since its onset, SCE has participated in the effort and held leadership positions within the governing board, the architecture committee and various Priority Action Plans (PAPs). SCE's director of Advanced Technology (AT) is a former governing board member for the "at-large" category. Additionally, AT's director of Engineering Advancement is a former member of SGIP's Implementation & Methods Committee (IMC). Furthermore, SCE has received various SGIP recognitions for its efforts in PAPs. SCE has participated in the first 16 PAPs, including:

- PAP 5: Standard Meter Data Profiles
- PAP 8: CIM for Distribution Grid Management
- PAP 11: Common Objective Models for Electric Transportation
- PAP 15: Harmonize Power Line Carrier Standards for Appliance Communication in the Home

PAPs have been an effective tool in identifying gaps among Smart Grid standards while providing standards development organizations (SDOs) with meaningful recommendations. However, PAP groups occasionally expand their focus beyond the immediate task. PAPs require proper NIST/SGIP leadership and oversight to avoid "scope creep." SCE has demonstrated this leadership by providing sound technical advice.

SCE remained a committed leader of the NIST standards effort through its final transition to the SGIP. SCE's decision to withdraw from the SGIP came when it was time to focus on system demonstrations and deployments. Resources that were previously allocated to standards development were transitioned to large demonstration projects such as the Irvine Smart Grid Demonstration (ISGD) project.

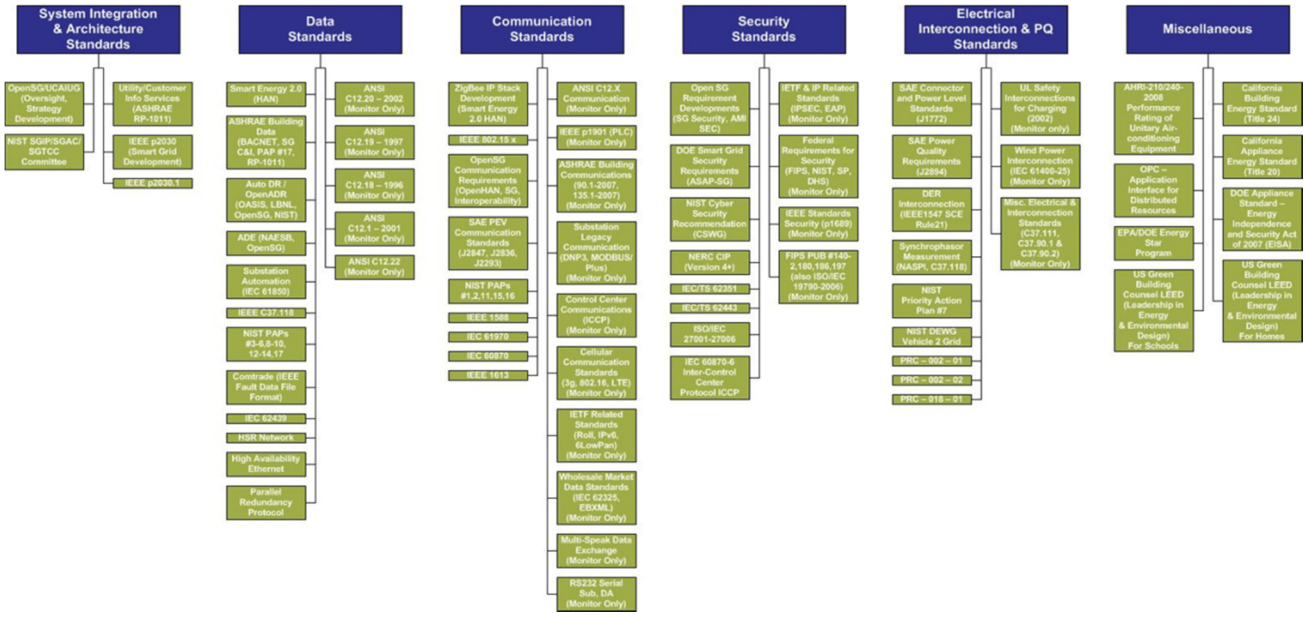
### *2. Standards Development*

SCE's vision of a Smart Grid requires developing, evaluating and implementing open standards. SCE identified five categories that represent the bases for developing the Smart Grid: System Integration & Architecture, Data, Communication, Security, and Electrical Interconnection standards. SCE has identified existing standards within these major categories and identified "gaps" within the existing standards. SCE prioritized the standards and assigned resources to either lead, support or monitor the particular standard. Using this process, SCE identified over seventy applicable standards and assigned resources to lead or support over forty standards. Some of the more notable standards either led or actively supported by SCE include:

- IEC 61850: Substation Automation
- Smart Energy 2.0: Home Area Network Communications
- NAESB ESPI: Automated Metered Data Exchange (e.g. Green Button)
- SAE J2836 & J2847: Electric Vehicle to Grid Communications

[34] Energy Independence and Security Act of 2007, Title XIII, Section 1305.

- SAE J2894: Electric Vehicle Charging Power Quality
- IEEE 1547: Distributed Energy Resources Interconnection
- ANSI C37.118: Synchrophasor Measurements
- IEEE P2030: Guide for SG Interoperability of Energy Technology
- OpenADR: Automated Demand Response
- Rule 21: California IOUs Standard to interconnect of distributed generation
- UL1741: Standard that mainly fallow IEEE 1547 but will incorporate a revision to California Rule 21

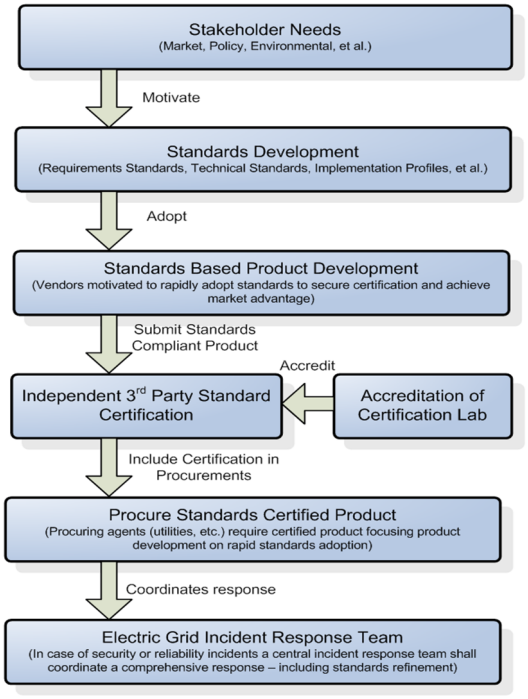



*SCE's Categorized List of Smart Grid Standards

## *3. Standards Conclusion*

SCE leads the industry in developing and supporting interoperability standards. The strategic standards development effort is focused on enabling grid modernization while maximizing system reliability, safety and customer value. SCE believes that proper standards development and adoption will ultimately lead to minimized risk to full Smart Grid deployments.

SCE continues to believe that standards are the key to minimizing risk and advancing the deployment of smart grid technologies. This is why SCE is now focused on demonstration of standards in order to encourage product manufacturers to move to the "standards based product development" stage of the standards life cycle. Until product manufacturers adopt these standards, it will be nearly impossible for electric utilities to fully adopt technologies. SCE is helping along this process by introducing a series of technology demonstrations and pilots that will hopefully lead to the systematic adoption of the smart grid standards portfolio.



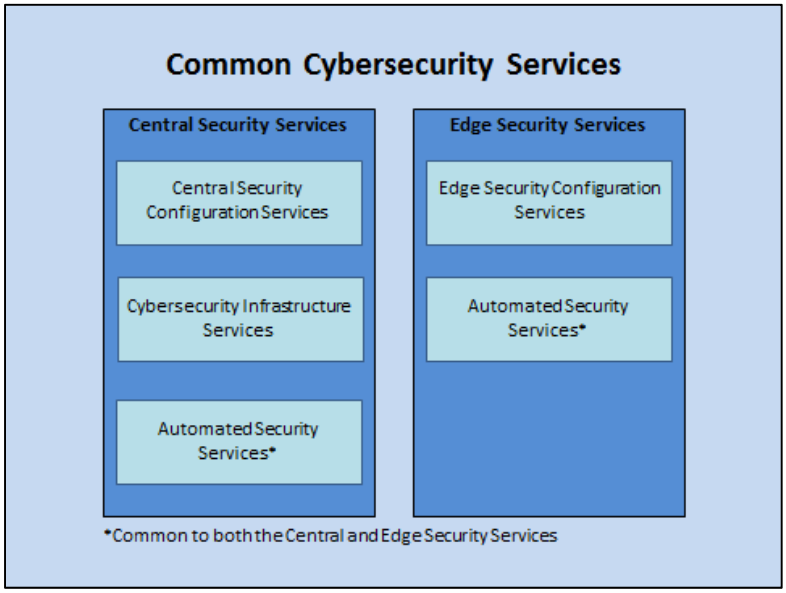

* Standards Life Cycle

## E. Cybersecurity Overview

The importance of cybersecurity to the utility industry and to SCE has expanded as systems and data have become more integral to business operations, and as the electric infrastructure has become more essential to national commerce and communication capabilities. Cyber attacks are continually growing in number and sophistication, and the availability of "cyber weapons" is on the rise as well. Therefore, maintaining a strong defense against cyber attacks requires a continually evolving set of strategies.

Over the past several years, SCE has been working to develop Common Cybersecurity Services (CCS) to protect its grid infrastructure, based on SCE's understanding that as the level of automation and connectivity increases through grid modernization, so does the vulnerability. This, coupled with the increasing threat of cyber attack inherent in the current geopolitical climate, requires deploying military-grade cybersecurity solutions to foster continued grid reliability. As of the writing of this document, CCS has been deployed in 27 Bulk Electric System substation across SCE's service territory. CCS is designed to implement security mechanisms to enforce confidentiality, integrity and availability in the form of security services and policies that protect electronic information communication and control systems necessary for the management, operation, and protection of key components of SCE's network and computing systems infrastructure as well as comply with NERC CIP Version 5. Furthermore, CCS is specifically designed to satisfy the Smart Grid requirements and standards developed by NERC, NIST, Department of Homeland Security, and DOE as part of the national effort on critical infrastructure and information protection standards as well as Smart Grid standards development.

The CCS is comprised of the Central Security Services (CSS) and Edge Security Services (ESS). CSS consists of Central Security Configuration Services, Cybersecurity Infrastructure Services, and Automated Security Services, which are physically located at the Grid Control Center, where electrical energy delivery is monitored and managed. The ESS consists of Edge Security Configuration Services and Automated Security Services, which provide distributed enforcement security on devices at or near the perimeter of a system.




The CCS solution enables the design and enforcement of policies that can be configured for specific devices, device classes or locations in the electric grid. Each device on the electric grid secured by CCS will have a unique key to enable secure communications with its control system. This approach mitigates the risk that an attacker will be able to seize control of the electric grid from one end device, such as a relay or capacitor bank controller. The approach also provides the flexibility to create virtual trust domains through the use of key groups to apply different levels of security and the ability to rapidly respond to a cybersecurity event.

SCE's experience and key learnings from our initial implementation has benefited the entire electric industry. The specifications and style of cybersecurity in CCS is being used to develop the IEC 61850-90-5 security standard. This should ultimately contribute to much more standardized and cost-effective implementation of robust cybersecurity on the electric grid.

### *1. Other Key Cybersecurity Initiatives*

SCE's commitment to cybersecurity goes well beyond the development and implementation of CCS and includes a number of other cybersecurity initiatives to help secure the enterprise. SCE employs a defense-in-depth strategy for security, which utilizes multiple layers of protection to prevent unauthorized access to its systems. SCE categorizes these initiatives into three primary categories:

1. Perimeter Defense: Perimeter Defense includes the process, procedures, personnel, hardware and software designed to protect SCE's information and systems from external attacks. Perimeter Defense is especially critical to systems that are accessible via the Internet.

2. Interior Defense: The goal of the Interior Defense program is to secure SCE's internal business systems from unauthorized users, devices and software. Advanced and integrated real time monitoring of SCE's internal business network makes it more difficult for unauthorized users to gain access to SCE's systems and for rogue devices or software to cause business disruption.

3. Data Protection: The objective of Data Protection program is to protect SCE customers, employees, contractors, and other personnel from identity theft, as well as to protect confidential SCE information residing on all computing devices from unauthorized use, distribution, reproduction, alteration, or destruction.

Additionally, SCE anticipates the need to respond to new legislation in the cybersecurity area, as cybersecurity legislation and regulation continue to evolve in response to terrorism, recent blackout, foreign state-sponsored cyberattacks, natural disasters, and increased reliance on the grid for essential services. As a large electric utility that is part of the critical national infrastructure, SCE strives to protect shareholder interests through shaping cybersecurity legislation and regulation, through early compliance planning.

### *2. Cybersecurity Conclusion*

SCE is an industry leader in cybersecurity with transformational strategies, architectures and solutions that enable grid modernization. SCE's focus on risk assessment, standards, architecture and cost effective solutions provides value to its customers and helps foster a safe and reliable grid that is able to support California's policy objectives in a reasonably cost-efficient manner.

## VI. Metrics Update

The metrics presented in this section quantitatively asses the progress in implementing Smart Grid-related policy goals in California, namely those enumerated in SB 17 (codified at Public Utilities Code Section 8360). These metrics, which were adopted by D.12-01-025, will provide the Commission with information to assist in the production of its annual report to the Legislature, as required under Public Utilities Code Section 8367. The adopted metrics are broken into four categories:

1. Customer/AMI Metrics;
2. Plug-In Electric Vehicles Metrics;
3. Storage Metrics; and
4. Grid Operations Metrics.

## A. Customer Metrics/ AMI Metrics

1. Number of advanced meter malfunctions where customer electric service is disrupted, and the percentage this number represents of the total of installed advanced meters.

| Metric - Meter Malfunctions | Total | Percent |
|---|---|---|
| Number of Advanced Meter Malfunctions Interrupting Customer Service | 10 | 0 |

An AMI meter failure resulting in a disruption of customer electric service would occur if there were a malfunction in the integrated service switch or other internal catastrophic failure. For the period of July 1, 2015 through June 30, 2016 there were 10 instances of an integrated service switch malfunction or other unplanned meter initiated customer interruptions. This metric does not include AMI meter malfunctions that do not result in service disruptions.

2. Load impact in MW of peak load reduction from the summer peak and from winter peak due to smart grid-enabled, utility administered demand response (DR) programs (in total and by customer class).

| Metric - Smart Grid Enabled DR | Customer Class | Load Impact Summer Peak (MW) | Load Impact Winter Peak (MW) |
|---|---|---|---|
| Load impact from smart-grid enabled, utility administered demand response programs | Residential | 3.12 | NA |
| | C&I < 200 kW | NA | NA |
| | C&I > 200 kW | NA | NA |
| | Ag & Pumping | NA | NA |
| | Total | 3.12 | NA |

During the reporting period, the average residential programmable communicating thermostat (PCT) customer delivered a .52 kW load impact, resulting in a 3.12 MW aggregate reduction.

3. Percentage of demand response enabled by AutoDR (Automated Demand Response) in each individual DR impact program.

| Metric - % Auto DR | Price Responsive Program | Percent |
|---|---|---|
| Percentage of demand response enabled by AutoDR by individual DR impact program | AMP | 16.6% |
| | CBP | 33.7% |
| | CPP | 15.5% |
| | DBP | 28% |

In 2015, SCE's demand response programs with AutoDR capabilities included the Aggregator Managed Portfolio, Capacity Bidding Program, Critical Peak Pricing, and the Demand Bidding Program. AutoDR load impacts from these programs were on average approximately 64 MWs in 2015.

This table shows the AutoDR average estimated ex post load impacts relative to each program's aggregate ex post load impacts. Ex post load impacts were estimated from regression analysis of customer-level hourly load data according to the Demand Response Load Impact Protocols (D.08-04-050). These results reflect the demand reductions delivered during historical events, based on the conditions that were in effect during that time.

4. The number and percentage of utility-owned advanced meters with consumer devices with HAN or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE status, and climate zone)

| Metric - HAN Registered Devices | Total | Percent |
|---|---|---|
| The number of utility-owned advanced meters with consumer devices with HAN or comparable consumer energy monitoring or measurement devices registered with the utility (by customer class, CARE, and climate zone, to extent available), excluding pilot participants | 1,906 | 0% |

As of June 30, 2016, SCE had successfully registered 1,189 customer-owned HAN devices that remained provisioned to smart meters. In addition, SCE has registered 717 utility provided devices that remained provisioned to smart meters as part of its HAN pilots.

Devices that connected with a different gateway are excluded. Also, devices that are connected to an energy management system, but not registered with the utility, are excluded (even though the energy management system may be registered with the utility). SCE does not currently have the capability to track devices by CARE/non-CARE and climate zone.

Note that widespread adoption of consumer HAN devices has not developed as expected due to delays with Smart Energy Profile 2.0 (no certified products as of this update), little interest to consumers for purchasing devices that provide energy consumption data, and alternative internet and home automation thermostats and other devices that provide remote access and control of electric loads. SCE expects organic growth of consumer HAN devices to be low and has seen an average of 30 new customer purchased HAN devices provisioned to smart meters each month.

5. Number and percentage of customers that are on a time-variant or dynamic pricing tariff (by type of tariff, by customer class, by CARE status, and by climate zone).

| | | | Baseline Region | | | | | | | | | | | Number of Residential Accounts: |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Program | CARE | 5 | 6 | 8 | 9 | 10 | 13 | 14 | 15 | 16 | Subtotal | Total | 4,354,658 |
| Residential | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of CPP Accounts: |
| | CPP | Non-CARE | - | 1 | 1 | - | - | - | - | - | - | 2 | 2 | 0.00% |
| | | CARE | 1 | 694 | 1,346 | 1,093 | 1,869 | 865 | 1,483 | 507 | 86 | 7,944 | | Percentage of TOU Accounts: |
| | TOU | Non-CARE | 11 | 8,621 | 7,948 | 7,005 | 7,716 | 860 | 2,183 | 1,524 | 601 | 36,469 | 44,413 | 1.02% |
| | | CARE | 1 | 12,023 | 28,354 | 23,805 | 34,803 | 4,342 | 10,711 | 3,589 | 1,320 | 118,948 | | Percentage of PTR Accounts: |
| | PTR | Non-CARE | 12 | 41,596 | 64,646 | 49,288 | 66,714 | 3,549 | 13,935 | 8,068 | 4,290 | 252,098 | 371,046 | 8.52% |
| | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of EV Accounts: |
| | EV | Non-CARE | - | 252 | 174 | 269 | 46 | - | 14 | 11 | 18 | 784 | 784 | 0.02% |

| | | | Baseline Region | | | | | | | | | | | Number of C&I >200 kW Accounts: |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Program | CARE | 5 | 6 | 8 | 9 | 10 | 13 | 14 | 15 | 16 | Subtotal | Total | 11,827 |
| C&I >200 kW | | CARE | - | 412 | 728 | 551 | 601 | 44 | 85 | 34 | 36 | 2,491 | | Percentage of CPP Accounts: |
| | CPP | Non-CARE | - | 4 | 40 | 20 | 22 | 1 | 1 | - | - | 88 | 2,579 | 21.81% |
| | | CARE | - | 413 | 731 | 553 | 602 | 44 | 85 | 34 | 36 | 2,498 | | Percentage of TOU Accounts: |
| | TOU | Non-CARE | 4 | 1,673 | 2,577 | 2,070 | 1,906 | 311 | 464 | 234 | 90 | 9,329 | 11,827 | 100.00% |
| | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of RTP Accounts: |
| | RTP | Non-CARE | - | 21 | 42 | 28 | 28 | 1 | 8 | 1 | 4 | 133 | 133 | 1.12% |
| | | CARE | - | 316 | 559 | 432 | 461 | 29 | 57 | 30 | 21 | 1,905 | | Percentage of EV Accounts: |
| | EV | Non-CARE | 3 | 1,042 | 1,739 | 1,414 | 1,273 | 178 | 291 | 153 | 49 | 6,142 | 8,047 | 68.04% |

| | | | Baseline Region | | | | | | | | | | | Number of C&I <200 kW Accounts: |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Program | CARE | 5 | 6 | 8 | 9 | 10 | 13 | 14 | 15 | 16 | Subtotal | Total | 605,241 |
| C&I <200 kW | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of CPP Accounts: |
| | CPP | Non-CARE | - | 2 | 13 | 15 | 13 | 451 | 30 | 3 | 4 | 531 | 531 | 0.09% |
| | | CARE | - | 33 | 10 | 20 | 12 | 4 | 4 | 1 | 1 | 85 | | Percentage of TOU Accounts: |
| | TOU | Non-CARE | 211 | 112,420 | 125,183 | 113,343 | 81,714 | 23,081 | 26,666 | 17,007 | 11,135 | 510,760 | 510,845 | 84.40% |
| | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of RTP Accounts: |
| | RTP | Non-CARE | - | - | - | - | - | - | - | - | - | - | - | 0.00% |
| | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of EV Accounts: |
| | EV | Non-CARE | - | 88 | 46 | 40 | 32 | 2 | 10 | 22 | 4 | 244 | 244 | 0.04% |

| | | | Baseline Region | | | | | | | | | | | Number ofAgricultural & Pumping Accounts |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Program | CARE | 5 | 6 | 8 | 9 | 10 | 13 | 14 | 15 | 16 | Subtotal | Total | 25,369 |
| Agricultural & Pumping | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of CPP Accounts: |
| | CPP | Non-CARE | - | - | - | - | - | - | - | - | - | - | - | 0.00% |
| | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of TOU Accounts: |
| | TOU | Non-CARE | 64 | 2,339 | 836 | 2,581 | 2,539 | 12,750 | 2,000 | 774 | 1,486 | 25,369 | 25,369 | 100.00% |
| | | CARE | - | - | - | - | - | - | - | - | - | - | | Percentage of RTP Accounts: |
| | RTP | Non-CARE | 1 | 11 | 3 | 1 | - | 2 | 3 | - | 4 | 25 | 25 | 0.10% |

In 2015, SCE discontinued the residential TOU-TEV rate plan concurrent with the implementation of the new TOU-D rate plan. Most customers previously on TOU-TEV have switched to the new rate plan which is available to all residential customers.

SCE currently offers four (4) different TOU rate plans to residential customers:

- TOU-D (Option A): typically a more appealing TOU rate option for customers with usage < 700 kWh per month. Has a lower daily charge, but higher energy price as compared with option B. Also includes a monthly baseline credit.
- TOU-D (Option B): typically a more appealing TOU rate option for customer with usage >700 kWh per month. Has a higher daily charge, but lower energy prices as compared with option A. Does not offer a baseline credit.
- TOU-D-T: a two-tiered (two pricing levels) TOU rate plan option.
- TOU-EV-1: requires a separate meter to measure consumption for EV charging.

SCE developed and launched three (3) new TOU pilot rate plans in support of the RROIR proceeding in June/July of 2015. These plans were offered to a targeted segment of residential customers on an opt-in basis and are not available to remaining residential customers. Learnings from the Opt-In TOU pilot will be used in the design of new TOU rates that will be introduced as part of the 2018 Default Pilot and 2019 full Residential Default to TOU.

The new TOU pilot rate plans include:

- TOU-D-1-P: this pilot rate plan is similar to the TOU-D (Option A) rate plan, with a summer on-peak from 2 PM to 8 PM, and offers a baseline credit element.
- TOU-D-2-P: provides a shorter 3 hour on-peak window (5 PM to 8 PM) with higher associated peak energy prices and offers a baseline credit element.
- TOU-D-3-P: offers differentiated pricing for 3 seasons of the year (spring, summer and winter), and has both a summer super on-peak period (4 PM to 9 PM), and split peak period (11 AM to 4 PM, and 9 PM to 11 PM). Does not offer a baseline credit.

6. Number and percentage of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) the functioning of a utility-administered Home Area Network with registered consumer devices.

| Metric - Customer Complaints | Complaint Type | Total | Percent |
|---|---|---|---|
| Number of escalated customer complaints related to (1) the accuracy, functioning, or installation of advanced meters or (2) or the functioning of a utility-administered Home Area Network with registered consumer devices | Meter Accuracy | 419 | 9.1% |
| | Meter Installation | 0 | 0.0% |
| | Meter Functioning | 50 | 1% |
| | HAN | 0 | 0% |

To calculate the percentages, SCE received a total of 4,928 escalated complaints during the period July 1, 2015 through June 30, 2016. SCE defines the types of customer complaints measured by this metrics as follows:

- Meter Accuracy – Escalated complaints to SCE's Consumer Affairs department related to high bills.
- Meter Installation – Escalated complaints to SCE's Consumer Affairs department regarding SCE's Edison SmartConnect installation contractor (e.g., damaged property during meter installation).
- Meter Functioning – Escalated complaints to SCE's Consumer Affairs department regarding issues such as radiofrequency/electromagnetic frequency, net energy metering reconciliation *(NEM customers who question bill accuracy due to the meter)*, and customer deployment opt-out requests.

7. The number and percentage of advanced meters replaced before the end of their expected useful life during the course of one year, reported annually, with an explanation for the replacement.

| Metric - Meter Replacement | Total | Percent |
|---|---|---|
| Number of utility-owned advanced meters replaced annually before the end of their expected useful life | 8,879 | 0.176% |

This metric includes the number of Advanced Metering Infrastructure (AMI) meters that were replaced after having been successfully installed during the three-year reporting period. The meter failure percentage is less than SCE's Edison SmartConnect™ business case assumption, as approved in D.08-09-039. The majority of AMI meters replaced before the end of their expected useful life were due to problems with the meter's Operating System, Random Access Memory, Data Flash or liquid crystal display failures. These predominant error types are consistent with previous year results. As of June 30, 2016, SCE had installed 5,041,538 AMI meters.

8. Number and percentage of advanced meters field tested at the request of customers pursuant to utility tariffs providing for such field tests, and the number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands.

| Metric - Meter Field Tests | Total | Percent |
|---|---|---|
| Number of advanced meter field tests performed at the request of customers pursuant to utility tariffs providing for such field tests | 1,959 | 0.04% |
| Number of advanced meters tested measuring usage outside the Commission-mandated accuracy bands. | 29 | 0.00% |

This metric includes the number of field tests performed by SCE personnel on Advanced Metering Infrastructure (AMI) meters at the customer's request pursuant to SCE's tariffs (number of customer request tests completed 1,959), and the number of AMI meters tested that measured usage outside of the Commission-mandated accuracy bands for the reporting period (outside of accuracy bands 29). A meter that is not registering or exhibits variable accuracy is also considered outside accuracy bands and, as such, included in the total. As of June 30, 2016, SCE had installed 5,041,538 AMI meters.

9. Number and percentage of customers using a utility web-based portal to access energy usage information or to enroll in utility energy information programs or who have authorized the utility to provide a third-party with energy usage data.

| Metric - Usage Info | Applicable Customer Class | Total | Percentage |
|---|---|---|---|
| Number and percentage of customers with advanced meters using a utility-administered internet or web-based portal to access energy usage information or to enroll in utility energy information programs | Unique Customers with Access to Interval Usage Data | 2,342,323 | 45.8% |
| | Unique Customers that have Accessed their Interval Usage Data | 1,663,012 | 32.5% |
| | Customers Enrolled in Energy Information Programs | 688,705 | 13.5% |

This metric reports the number of customers that have enrolled in SCE's MyAccount and have access to their interval usage data through SCE's website, and the number of customers who accessed their interval usage data during the Reporting Period. In addition, this metric reports customers enrolled in SCE's Budget Assistant Program, which provides customers with automated proactive performance notifications based on a preset monthly spending goal. This metric excludes customers accessing usage information through non-utility portals, and also excludes customer accessing cumulative usage information. As of June 30, 2016, there were 5,114,708 customers with an Edison SmartConnect meter.

## B. Plug-in Electric Vehicle Metrics

1. Number of customers enrolled in time-variant electric vehicles tariffs.

SCE offers three time-variant electric vehicle tariffs with the following enrollment as of 6/30/16:

| Metric - PEV Tariff Enrollment | Residential | | Commercial | |
|---|---|---|---|---|
| Number of customers enrolled in time-variant electric vehicles tariffs | TOU-EV-1 | 791 | TOU-EV-3 | 39 |
| | | | TOU-EV-4 | 81 |

In 2015, SCE discontinued the residential TOU-TEV and implemented the new TOU-D. Most customers previously on TOU-TEV have switched to the new rate plan (the plan is available to all residential customers). As of June 2015, SCE had 8,733 customers on TOU-D.

TOU-EV-1 is available to residential customers. TOU-EV-3 and TOU-EV-4 are only available for non-residential customers charging electric vehicles on a single dedicated meter. TOU-EV-3 is available to customers whose monthly maximum demand is 20 kW or less while TOU-EV-4 is available to customers whose monthly maximum demand is above 20 kW, but does not exceed 500 kW.

## C. Storage Metrics

1. MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals.

| Metric - Energy Storage | # of Facilities | Total MWs | Total MWhs/yr |
|---|---|---|---|
| MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals | 1 | 200 MWs | 189,052 MWhs/yr |

As of July 30, 2016, SCE's Eastwood power station – a pumped storage hydro facility located within the broader Big Creek complex – represents the largest energy storage facility interconnected to either SCE's transmission or distribution system. This pumped storage hydro facility has a capacity of approximately 200 MWs and produces about 202,000 MWh per year. [35]

## D. Grid Operations Metrics

1. The system-wide total number of minutes per year of sustained outage per customer served as reflected by the System Average Interruption Duration Index (SAIDI), Major Events Included and excluded for each year starting on July 1, 2011 through the latest year that this information is available. [36]

| Metric - SAIDI | Year | Major Events Included | Major Events Excluded |
|---|---|---|---|
| System-wide total number of minutes per year of sustained outage per customer served as reflected by SAIDI | 2001 | 60.00 | 45.71 |
| | 2002 | 52.29 | 44.95 |
| | 2003 | 89.26 | 53.37 |
| | 2004 | 74.93 | 55.30 |
| | 2005 | 92.26 | 72.57 |
| | 2006 | 134.39 | 87.21 |
| | 2007 | 163.15 | 95.89 |
| | 2008 | 107.48 | 95.43 |
| | 2009 | 119.18 | 90.70 |
| | 2010 | 141.20 | 100.25 |
| | 2011 | 223.42 | 107.98 |
| | 2012 | 100.45 | 98.23 |
| | 2013 | 106.17 | 88.08 |
| | 2014 | 106.83 | 96.94 |
| | 2015 | 148.90 | 114.96 |

[35] The annual energy production of SCE's pumped hydro facility varies from year to year depending on hydrological reserves and resource dispatch requirements.

[36] Values provide for SAIDI represent a July-to-June snapshot and should not be confused with the values provided by SCE within its Annual System Reliability Report which is done on a calendar year basis.

2. How often the system-wide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. [37]

| Metric - SAIFI | Year | Major Events Included | Major Events Excluded |
|---|---|---|---|
| How often system-wide average customer interrupted in reporting year as reflected by SAIFI | 2001 | 1.19 | 0.97 |
| | 2002 | 1.27 | 1.05 |
| | 2003 | 1.39 | 1.11 |
| | 2004 | 1.34 | 1.15 |
| | 2005 | 1.53 | 1.33 |
| | 2006 | 1.01 | 0.82 |
| | 2007 | 1.16 | 0.95 |
| | 2008 | 1.02 | 0.96 |
| | 2009 | 0.87 | 0.76 |
| | 2010 | 1.06 | 0.86 |
| | 2011 | 1.01 | 0.89 |
| | 2012 | 0.90 | 0.89 |
| | 2013 | 0.92 | 0.83 |
| | 2014 | 0.90 | 0.86 |
| | 2015 | 1.12 | 0.99 |

[37] Values provided for SAIFI represent a July-to-June snapshot and should not be confused with the values provided by SCE within its Annual System Reliability Report pursuant to D.96-09-045.

3. The number of momentary outages per customer system-wide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. [38]

| Metric - MAIFI | Year | Major Events Included | Major Events Excluded |
|---|---|---|---|
| Number of momentary outages per customer system-wide per year, as reflected by MAIFI, major events included and excluded | 2001 | 1.16 | 1.08 |
| | 2002 | 1.15 | 1.09 |
| | 2003 | 1.43 | 1.15 |
| | 2004 | 1.21 | 1.05 |
| | 2005 | 1.47 | 1.23 |
| | 2006 | 1.78 | 1.41 |
| | 2007 | 1.90 | 1.60 |
| | 2008 | 1.50 | 1.38 |
| | 2009 | 1.55 | 1.38 |
| | 2010 | 1.62 | 1.38 |
| | 2011 | 1.49 | 1.33 |
| | 2012 | 1.31 | 1.29 |
| | 2013 | 1.29 | 1.19 |
| | 2014 | 1.28 | 1.23 |
| | 2015 | 1.65 | 1.43 |

4. Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2011 through the latest year that this information is available.

| Metric | Year | Customers/yr | Circuits/yr |
|---|---|---|---|
| Number of customers per year and circuits per year, experiencing greater than 12 sustained outages | 2001 | 2,605 | 9 |
| | 2002 | 1,896 | 4 |
| | 2003 | 7,212 | 19 |
| | 2004 | 12,269 | 26 |
| | 2005 | 3,123 | 13 |
| | 2006 | 93 | 2 |
| | 2007 | 741 | 3 |
| | 2008 | 1,473 | 16 |
| | 2009 | 435 | 8 |
| | 2010 | 167 | 5 |
| | 2011 | 1,243 | 7 |
| | 2012 | 11,625 | 2 |
| | 2013 | 7 | 1 |
| | 2014 | 1,083 | 7 |
| | 2015 | 2,209 | 10 |

[38] Values provided for MAIFI represent a July-to-June snapshot and should not be confused with the values provided by SCE within its Annual System Reliability Report pursuant to D.96-09-045.

5. System load factor and load factor by customer class for each year starting on July 1, 2011 through the latest year that this information is available.

| Metric - Load Factor | Customer Class | 2014 Load Factor |
|---|---|---|
| System load factor and load factor by customer class | Residential | 33% |
| | C&I < 200 kW | 49% |
| | C&I > 200 kW | 66% |
| | Ag & Pumping | 63% |
| | System | 52% |

Load factor is defined as the average load throughout a given year divided by the peak load during that same year. This value can be calculated for an entire system or a specific customer class and is typically used as a measure of how effectively generation capacity is used. SCE calculates system load factor and load factor by customer class every year as part of its annual rate group load studies, which are leveraged for analyses in the Phase II (Rate Design) of the GRC. This process leverages statistically valid load data from over 55,000 customers, representing all classes of Edison customers, with about 35,000 data points per sampled customer. Load factors by customer class often reside outside of the system-wide range because of their differing load profiles, or energy consumption patterns.

6. Number of and total nameplate capacity of customer-owned or operated, grid-connected distributed generation facilities.

| Metric - DG Number & Capacity | Program | # of Facilities | Total Capacity (MW) |
|---|---|---|---|
| Number of and total nameplate capacity of customer-owned or operated, utility grid-connected distributed generation facilities<br><br>* Data are as available for period 7/1/2011 – 4/30/2016 | CREST* | 81 | 108.76 |
| | Re-MAT* | 3 | 6.50 |
| | RSC* | 10 | 114.00 |
| | RAM* | 21 | 296.03 |
| | SPVP (IPP)* | 21 | 41.64 |
| | SPVP (UOG)* | 11 | 41.0 |
| | CSI | 49,102 | 588.4 |
| | SGIP | 282 | 27.9 |
| | **TOTAL** | **49,531** | **1,224** |

SCE offers two state-mandated incentive programs, the California Solar Initiative (CSI) and the Self-Generation Incentive Program (SGIP), for customer side of the meter DG, also referred to as "onsite generation" or "self-generation." The CSI rebate program ended last year with only 360 projects at an additional 68 MW in capacity installed as part of the incentive program within the reporting period of July 2015 to June 2016. Since July 2011, just over 49,000 CSI systems have been installed with a capacity of about 588 MW in conjunction with SCE administered incentive programs as of the end of the Reporting Period. CSI Residential Incentives were depleted in Q1 2014, while SGIP increased due to the addition of Advanced Energy Storage technology (Batteries that can paired with any existing SGIP technology (solar, fuel cells, wind, etc.). While CSI installations continued at a very heavy pace during the Reporting Period, almost none of them were part of an incentive program.

SCE also supports programs and policies related to procurement of utility-side of the meter DG. This is also called "wholesale" or "system-side generation" because it is intended to net export onto the electrical system on the other side of the customer meter or connect to the distribution system directly. SCE offers a renewable feed-in tariff under the Renewable Market Adjusting Tariff (Re-MAT) program which executes a power purchase agreement where SCE will pay for either the total or excess energy a customer generates through facilities not greater than 3 MW. This program accommodates all eligible renewable technologies up to a total of 143.6 MW as of August 2016. SCE's Solar Photovoltaic Program (SVPV) allows SCE, over a five-year period, to build and operate no less than 91 MW of utility-owned solar photovoltaic capacity and to execute contracts up to 125 MW for generation from similar facilities owned and maintained by independent power producers (IPPs) through a competitive solicitation process.[39] This program is applicable to primarily rooftop solar PV facilities with a small portion of ground mounted facilities.

SCE offers a Renewable Auction Mechanism (RAM), which is a simplified and market-based procurement mechanism for renewable DG projects up to 20 MW on the system side of the meter. Following the completion of the sixth RAM request for proposals ("RAM 6 RFO") in early 2016, SCE has met its requirement of 787.4 MW and has completed the RAM Program.

[39] The RAM component of SPVP involves procuring 284 MW DC of SPVP through RAM (256 MW AC). This 256 MW AC is subject to RAM protocols and practices. Please see D.13-05-033, Attachment 1.

7. Total electricity deliveries from customer-owned or operated, grid-connected distributed generation facilities, reported by month and by ISO sub-Load Aggregation Point.

| Metric - DG Electric Deliveries | Program | kWhs |
|---|---|---|
| Total annual electricity deliveries from customer-owned or operated, utility grid-connected DG facilities<br><br>* Data are as available for period 7/1/2011 – 4/30/2016 | CREST* | 518,903,436 |
| | Re-MAT* | 6,638,557 |
| | RSC* | 564,413,023 |
| | RAM* | 838,926,024 |
| | SPVP (IPP)* | 180,414,046 |
| | SPVP (UOG)* | 262,005,166 |
| | NSC | 4,451,377 |
| | **TOTAL** | 2,375,751,629 |

Facilities brought online under SCE's CREST/WATER, RE-MAT, RSC, RAM, SPVP, and net surplus compensation (NSC) programs together produced nearly 2.4 billion kWh. This value captures only electric deliveries to the grid; it does not represent the total energy production of distributed generators in SCE's service territory. All of the energy provided by distributed generators in either the CSI or SGIP programs is "customer side of the meter," meaning that it first serves onsite customer load requirements before feeding any excess energy onto the distribution system. Customers matching this load profile have the option to subscribe under SCE's NSC rate, which pays customers who produce more kilowatt hours than they consume in a 12-month period.

8. Number and percentage of distribution circuits equipped with automation or remote control equipment, including Supervisory Control and Data Acquisition (SCADA) systems.

| Metric - Circuit Automation | # of Automated Circuits | Total Circuits | % Automated |
|---|---|---|---|
| Number and percentage of distribution circuits equipped with automation or control equipment, including Supervisory Control and Data Acquisition (SCADA) systems - Reporting Start Date - July 2012 | 2,841 | 4,638 | 61% |

As of June 30, 2016, SCE had a total of 4, 638 distribution circuits in operation – 2,841 of which are automated with mid and/or tie remote control switches. This metric indicates that 61 percent of circuits can be remotely monitored and controlled through SCE's existing DMS system to protect critical distribution equipment, restore outages, and minimize customer minutes interrupted.

## Appendix 1

# Smart Grid Customer Engagement by Initiative

**Smart Grid Engagement by Initiative.** As requested by CPUC staff in its March 1, 2012 Smart Grid Workshop Report, the information presented in this appendix provides the customer engagement elements (i.e., project description, target audience, sample message, source of message, current road blocks and strategies to overcome roadblocks) for the following initiatives:

**Customer Premise Devices**

A. Near Real-Time Usage (HAN)

**Online Tools**

B. Integrated Audit Tool

C. Web Presentment Tools

D. Budget Assistant

E. Green Button Download My Data

F. Green Button Connect My Data

G. Mobile-Optimized Outage Center

**Rates and Programs**

H. Save Power Day (PTR)

I. PEV Time-of-Use Rates

J. Residential TOU Rates

**Customer Premise Devices**

**A. Near Real-Time Usage (HAN)**

| | |
|---|---|
| **Project Description** | ME&O to educate customers regarding near real-time usage data which can display a customer's current usage on a registered display device with an approximately 12-second delay. |
| **Target Audience** | Residential and small/medium non-residential customers with demands less than 200 kW. |
| **Sample Message** | Beginning in 2010, SCE developed messaging to market Home Area Network (HAN) devices and their potential benefits to customers through a variety of pilot and production programs. These included an In-Home Display (IHD) field trial, Interim HAN Solution and Real Time Cost Pilots targeting a larger population with IHDs, and partnerships with ADT and DirecTV to provide HAN devices to SCE customers. SCE also updated SCE.com with information to educate customers about HAN devices and provide an automated way for them to register HAN devices purchased at retail. The information and automated registration on SCE.com has been in place and operational since 2013 when SCE completed HAN related pilots and began offering the ability for virtually any residential customer to purchase and register a HAN device with their smart meter. |
| **Source of Message** | Utility and third parties that leverage the data for energy service offerings. |
| **Current Customer Engagement Road Block(s)** | Although efforts have been made to educate customers about HAN devices and potential benefits, a robust retail market of HAN devices has not developed as anticipated, results from SCE pilots and programs haven't shown long term benefits, and customers haven't seen enough value from HAN devices to justify purchasing them. In addition, a variety of internet connected thermostats and home automation systems have gained traction in the consumer marketplace as an alternative to HAN devices. |
| **Strategy to Overcome Roadblocks** | Based on consumer needs and the evolving marketplace, HAN devices have been superseded by internet connected home automation devices such as smart thermostats. SCE's strategy has been to support the needs of the marketplace and develop |

| | |
|---|---|
| | programs that utilize devices being purchased and installed by our customers. However, we will continue to support customers who purchase HAN devices and connect them to their smart meter for a period of time. |

**Online Tools**

### B. Integrated Audit Tool

| | |
|---|---|
| **Project Description** | ME&O to generate participation in SCE's online integrated audit tool, Home Energy Advisor (for residential customers) and the Business Energy Advisor (for business customers). Upon completion of an integrated survey (audit), customers will receive customized DSM recommendations that will help customers better manage their energy usage. The integrated audit tool was implemented on October 31, 2015. |
| **Target Audience** | Residential and business customers. |
| **Sample Message** | Answer some questions to get an analysis of your energy use, along with customized recommendations for how to save and where to start. Then, let the tool work for you by tracking your progress, updating your actions and seeing the savings. |
| **Source of Message** | Utility |
| **Current Customer Engagement Road Block(s)** | • The tool was implemented without a Single Sign-On (SSO) capability. As a result, the customer may have to carry multiple user name and passwords. |
| **Strategy to Overcome Roadblocks** | • Implement SSO in 3rd Quarter 2016. |

### C. Web Presentment Tools

| | |
|---|---|
| **Project Description** | ME&O to educate customers about online tools that provide interval energy usage and billing data that enable customers to make better energy management decisions. Online tools include: estimated bill-to-date, projected next bill, and interval data charts. See SCE Advice 2693-E[40] for more information about these tools. |
| **Target Audience** | Residential and small/medium non-residential customers with demands less than 200 kW who have a smart meter that is measuring interval data for billing purposes. |
| **Sample Message** | "Online tools can help you take control of your energy bills." |
| **Source of Message** | Utility |
| **Current Customer Engagement Road Block(s)** | • Customers need internet access to take full advantage of the tools.<br>• Low customer adoption rate. |
| **Strategy to Overcome Roadblocks** | • Customers who do not have internet access can obtain information on their interval energy usage and billing data through the call center.<br>• Bundle tools with other relevant products, rates and services, such as TOU rates.<br>• Integrate relevant information into appropriate marketing materials. |

[40] Advice 2693-E is pending disposition from the Commission.

**D. Budget Assistant**

| | |
|---|---|
| **Project Description** | ME&O to educate customers regarding SCE's Budget Assistant tool which allows customers to easily monitor energy usage and costs. ME&O will be used to educate, inform and enroll customers by communicating that Budget Assistant helps eliminate end of the month bill surprises by providing alert notifications. See SCE Advice 2693-E for more information about this tool. |
| **Target Audience** | Most residential and small/medium non-residential customers with demands less than 200 kW. |
| **Sample Message** | "Manage and control your electricity costs when you set a monthly spending goal and get updated with trigger based or weekly notifications via email, text or voice message – eliminating any end-of-the-month bill surprises." |
| **Source of Message** | Utility |
| **Current Customer Engagement Road Block(s)** | • Customers must enroll in the program to receive alerts.<br>• Lack of customer awareness of alerts. |
| **Strategy to Overcome Roadblocks** | Bundle tool and cross-promote with other relevant products, rates and services. |

**E. Green Button Download My Data**

| | |
|---|---|
| **Project Description** | Green Button is a White House initiative to allow customers greater access to their usage data via a "Green Button" on sce.com. Green Button will allow customers to download up to thirteen months of historical interval usage data in a data format that is standard across utilities. |
| **Target Audience** | All Customers |
| **Sample Message** | Green Button icon and "Download My Data" message provided on SCE.com. |
| **Source of Message** | The messaging source is third parties that leverage Green Button data for their energy service offerings. |
| **Current Customer Engagement Road Block(s)** | SCE will provide the Green Button data, but does not market or offer any services that will use the Green Button data beyond providing the Green Button icon, Download My Data, or Connect My Data on SCE.com. |
| **Strategy to Overcome Roadblocks** | Third parties, CPUC, and IOUs should monitor national Green Button developments, continue discussions with the U.S. Department of Energy, and respond as appropriate. |

**F. Green Button Connect My Data**

| | |
|---|---|
| **Project Description** | SCE provides third parties access to individual customer's smart meter usage data via the utility's "backhaul" when authorized by the customer, and in a common data format consistent with the ongoing national Smart Grid standards efforts. The Customer Data Access, known as Green Button Connect, will leverage the Energy Service Provider Interface (ESPI) platform to transfer the data. |
| **Target Audience** | Green Button Connect is available for all customers. |
| **Sample Message** | SCE will provide 3rd Parties a unique URL during registration. This link will be sent to customers by their designated 3rd parties to streamline the customer authorization process. These third parties will market services to customers and develop messaging consistent with their energy service offerings. |
| **Source of Message** | Third parties that leverage Green Button Connect for their energy service offerings. |
| **Current Customer Engagement Road Block(s)** | The majority of engagement with customers regarding the use of this service will come from the third parties that offer energy management services that can leverage Green Button Connect. The Green Button Connect program was made available in November 2014. |
| **Strategy to Overcome Roadblocks** | Pursuant to D.13-09-025, SCE filed an Advice Letter providing key details about Green Button Connect My Data that leverages the ESPI platform. |

### G. Mobile-Optimized Outage Center

| | |
|---|---|
| **Project Description** | ME&O to educate customers on the mobile-optimized SCE Outage Center. Customers can view the status of outages and report outages on their smart phone or tablet. See SCE.com for more information. |
| **Target Audience** | Customers who use a smart phone or tablet. |
| **Sample Message** | "We know you depend on your mobile phone to communicate and stay safe during an emergency. If you experience a power outage, use your phone's web connection to report outages and view outage locations as well as find out when your service may be restored. Visit sce.com/outage. You can also use this site to report street light outages and find or report current outages at any time." |
| **Source of Message** | Utility |
| **Current Customer Engagement Road Block(s)** | • Customer must have an internet connected device to use the mobile-optimized Outage Center.<br>• Lack of customer awareness of this tool. |
| **Strategy to Overcome Roadblocks** | • Customers without an internet connected device can continue to call to report an outage.<br>• Integrate educational materials regarding this tool in appropriate marketing materials and sce.com. |

**Rates and Programs**

### H. Save Power Day (Peak Time Rebate)

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| **Project Description** | ME&O to educate customers on SCE's Peak Time Rebate Program (PTR) marketed as the Save Power Day (SPD) program. Customers choosing to participate need to enroll to qualify to receive program related incentives. Customer can choose to receive SPD event notifications through voice text, or email. . When an SPD event is called, customers can choose to reduce electricity use between the hours of 2pm and 6pm in order to earn bill credits. The Save Power Day program is structured to provide customers with multiple enrollment and incentive options:<br><br>1. Base Program: Provides an incentive of $0.75 per kWh reduced during events (aka PTR).<br>2. Enhanced Program: Provides an incentive of $1.25 per kWh reduced during events for customers with a HAN device provisioned with their smart meter (aka PTR-ET).<br><br>Enhanced Program with Load Control: Provides an incentive of $1.25 per kWh reduced during events for customers with an eligible and enabled 3rd Party load control device (aka PTR-ET-DLC).<br><br>On December 9, 2015 SCE filed Advice Letter 3323-E to the commission requesting approval to discontinue PTR and PTR-ET in 2016 due to low per-customer savings, poor cost-effectiveness, and low dispatch flexibility. Delays in receiving a timely decision and the need for resources to alleviate potential issues related to Aliso Canyon resulted in SCE withdrawing AL 3323-E. |
| **Target Audience** | Residential customers with a smart meter that is measuring interval data for billing purposes. |
| **Sample Message** | "Sign Up for Save Power Days to Earn Up to $100* In Bill Credits."<br><br>Save Power Day vs. Flex Alert: What's the Difference?<br><br>A Save Power Day is issued by SCE, and we credit you with incentives of up to $100* each year when you conserve on |

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| | these specific days. A Flex Alert, however, comes from the State of California, and while there is no incentive for participating in a Flex Alert, it is important to save energy when one is called.<br><br>Save Power Days vs. Summer Discount Plan<br><br>The Save Power Day program is voluntary and provides customers with the option to reduce energy use during planned events by turning off or unplugging the appliances of their choice. The Summer Discount Plan is also a voluntary program but provides the utility with permission to cycle off the customer's air conditioning unit during periods of high demand. Occasionally a Save Power Day and Summer Discount Plan event will be called on the same day, which provides customers enrolled in both programs with the ability to save even more! Learn more about Summer Discount Plan and enroll today to maximize your savings during the summer months. |
| **Source of Message** | Utility |
| **Current Customer Engagement Road Block(s)** | • Customer confusion regarding the differences between Save Power Day events, Summer Discount Plan events, and statewide Flex Alerts.<br><br>• Lack of awareness and understanding regarding what Save Power Day events and/or alerts represent.<br><br>• Customers need to sign up to receive an alert via text, email, or voice messaging. |
| **Strategy to Overcome Roadblocks** | • Continue communications to help customers recognize and understand the difference between Save Power Day, Summer Discount Plan, and Flex Alert. |

## I. PEV Time-of-Use Rates

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| **Project Description** | ME&O to educate customers on PEV rate options, environmental benefits, charging levels, and other aspects of PEVs. Materials encourage customers to contact the utility prior to taking delivery of a PEV which will better inform the customer and start the process for SCE to check the distribution infrastructure for safe and reliable charging. See SCE.com for more information about PEV TOU rates. |
| **Target Audience** | Customers who have notified SCE of their interest in purchasing a PEV, customers who have notified SCE of their interest in providing a charging station(s) (i.e., fleet, workplace, commercial and multifamily dwelling charging), auto dealers, manufacturers, electricians, and installers. |
| **Sample Message** | In the market for an EV? Rate Assistant shows you just how much you can save. Learn more at sce.com/pev.<br><br>Thinking of buying an EV? Before you plug in a car. Plug in the numbers to see how much you can save. Explore Rate Assistant from SCE. |
| **Source of Message** | Utility and third parties |
| **Current Customer Engagement Road Block(s)** | • Customers do not think about contacting the utility prior to purchasing and/or taking delivery of their new PEV.<br><br>• Dealers have some apprehension to introducing the role of the utility during the sales process. |
| **Strategy to Overcome Roadblocks** | • Conduct online advertising to generate awareness of the role of the utility and PEVs.<br><br>• Launched online EV Assessment Tool on SCE.com.<br><br>• Launched "What's Your EV IQ?" banner ad campaign to inform customers about an EV's cost savings and environmental benefits, and seek to address range anxiety. Campaign aims to intrigue and engage people by challenging them with fun mini-quizzes, and provides an opportunity to inform them of EV benefits that could motivate them to consider driving an EV. |

**J. Residential TOU Rates**

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| **Project Description** | Optional Residential Time-of-Use rates provide customers with the ability to take more control over their energy costs. SCE currently offers several residential TOU rate plans.<br><br>On July 3, 2015, the CPUC approved a decision on Residential Rate Reform (RROIR) which sets forth a glide path for restructuring the tiered rate plan and transitioning Residential customers to time differentiated rates.<br><br>As part of that transition, SCE launched a TOU Opt-in Pilot on June 1, 2016 for 22k customers to test retention and behavior on various time-of-use rates. The pilot runs through Dec 31, 2017. |
| **Target Audience** | Residential customers |
| **Sample Message** | Take more control of your electricity bill – new Time-of-Use rate plans offer different pricing during different times of the day/week providing you with the ability to better manage your energy costs. |
| **Source of Message** | SCE.com/My Account; targeted outreach campaigns; broad awareness campaigns; statewide communications. |
| **Current Customer Engagement Road Block(s)** | • Information clutter<br>• Low interest topic area<br>• Savings require a behavior change in most cases<br>• Saving may not be significant enough to motivate change<br>• Customers must take a more active role with managing their energy use |
| **Strategy to Overcome Roadblocks** | • Creative messaging<br>• Creative engagement strategies<br>• Improve CSRs Rate knowledge / literacy<br>• Pilot testing<br>• Targeted solicitations |

**Pilot and Demonstration Programs.** In addition to the initiatives described above, SCE has launched a Customer Empowerment pilot. Generally, SCE will provide pilots to a limited target audience for a limited duration and SCE will not provide ME&O to its general customer population. However, pilots are expected to provide SCE with an improved assessment of potential messaging, customer engagement roadblocks, and potential strategies to overcome such roadblocks. Information regarding specific SCE Customer Empowerment efforts is provided below:

- **TOU Opt-in Pilot**. The TOU Opt-in Pilot was launched on June 1, 2016 an in effort to test a number of objectives in the pilot design to help inform 2019 TOU residential default. These objectives include but are not limited to the following:

    a. Assessing customer understanding /acceptance / engagement /satisfaction /retention with various TOU rate options

    b. Assessing the degree of hardship that might result from default TOU rates on senior households and economically vulnerable customers (and perhaps others) as directed by Public Utilities Code Section 745

    c. Assessing adoption rates for enabling technology for customer on TOU rates

    d. Assessing the effectiveness of education and outreach options

## Appendix 2

# Description of Baseline Regions

**Map of Baseline Regions**